Electric Power In Canada

1983

DRAFT - PROJET

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Capacity:	The rated ability of facilities to produce or deliver power at a given point in time. Installed generating capacity means the maximum amount of power that can be generated at any time.
Power:	The time rate at which electrical energy is made available, or consumed, typically measured in kilowatts.
Production:	Generation of electrical energy, typically measured in kilowatt-hours.
Consumption:	Use of electrical energy, typically measured in kilowatt-hours.

Power:	kW - kilowatts		
	MW - megawatts	=	1,000 kW
	GW - gigawatts	=	1,000,000 kW
	TW - terawatts	=	1,000,000,000 kW
Energy:	kWh - kilowatt-hours		
	MWh - megawatt-hours	=	1,000 kWh
	GWh - gigawatt-hours	=	1,000,000 kWh
	TWh - terawatt-hours	=	1,000,000,000 kWh
Voltage:	kV - kilovolts = 1000 Volts.		

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CONSUMPTION, PRODUCTION AND CAPACITY

Consumption

Electricity demand in Canada experienced an exceptionally strong increase during the last two-thirds of the year after a very weak beginning. During the period January to April, demand declined 4.0% relative to the same period of 1982, as a result of very mild weather and weak economic performance. However, over the period May to December cumulative demand was 9.0% above that of the same period in 1982. This strong growth was in some measure related to increased space conditioning (cooling in the very warm summer and heating during the fall and winter months) relative to 1982 but probably principally related to improved economic growth. Over the whole year, electricity demand increased by 4.6% to 360 billion kilowatt-hours. Real economic growth, to which electricity demand is highly correlated, increased by 3.0%, as measured by real (i.e. net of inflation) gross national product (GNP). Thus, the electricity intensity of the Canadian economy in 1983 continued its long-term growth trend; kWh per $ of real GNP (1971 $) was 2.70, up from 2.58 in 1980, 2.35 in 1975 and 2.29 in 1970.

The growth of electricity used in Canada in 1983 relative to 1982 varied considerably from one province and one utility to another, as shown below:

Table: I Percentage Change of Electricity Use in Canada 1983-1982.

	Province	Major Utilities
Newfoundland	3.2	5.4
Prince Edward Island	3.9	3.9
Nova Scotia	1.6	0.1
New Brunswick	8.5	10.0
Quebec	3.7	2.6
Ontario	5.6	5.2
Manitoba	2.8	3.0
Saskatchewan	6.3	5.8
Alberta	6.0	7.0
British Columbia	1.9	1.2
Yukon/Northwest Territories	-16.4	-9.1
Canada	4.6	4.0

New Brunswick experienced the strongest growth at 8.5% followed closely by Alberta, Ontario and Saskatchewan with growth of about 5.5%-6.5%

The stronger industrial sector provided the biggest boost, although weather conditions resulted in higher space conditioning demands for electricity. It is probable that improved resource sector production provided the major boost in New Brunswick, Saskatchewan and Alberta; increased production from the manufacturing industry caused much of the demand growth in Ontario.

Production

Generation for the year was 395 TWh, an increase of 4.9%. Of this production, 360 TWh was for use in Canada and the remainder was exported. The sources of generation were as follows:

Table 2: Generation Source of Production

Generation Type	% of 1983 Generation	% of Production Increase from 1982
Hydro	67	3.0
Nuclear	12	27.8
Thermal	21	0.9

The increased nuclear generation resulted from putting into service the first nuclear generation units in Quebec and New Brunswick as well as an additional unit in Ontario.

Capacity

Total generating capacity increased by 3,440 MW in 1983, to 88,951 MW at year end, a 4.0% increase over 1982. Hydro capacity additions totalled 1,505 MW, conventional thermal 734 MW and nuclear 1,201 MW, representing 44%, 21% and 35% of the total additions, respectively. Major additions are detailed below:

Table 3: Major Changes to Installed Capacity During 1983

Province	Project	Plant Type	No. of Units	Capacity MW
Additions				
Newfoundland	Salmon Arm	Hydro	1	84
Nova Scoita	Lingan 3	Steam (coal)	1	150
Quebec	La Grande 3	Hydro	7	1344
	Gentilly	Nuclear	1	685
Ontario	Pickering B Unit 5	Nuclear	1	540
Saskatchewan	Poplar River	Steam (coal)	1	300
Alberta	Keephills	Steam (coal)	1	400

Table 4A Electricity Supply/Demand: Total for Canada 1982-1983.

	1983	1982**	% Change
Total demand for electricity (GWh)	359 454	345 115	4.1
Total generation (GWh) by:	395 490	376 485	4.9
hydro	262 862	255 185	3.0
nuclear	46 221	36 168	27.8
conventional thermal	85 922	85 132	0.9
Total net exports (GWh)	35 551	31 371	13.3
total imports	2 757	2 855	-3.4
total exports	38 308	34 226	11.9
- firm *	10 218	5 829	75.3
- interruptible *	26 689	27 157	-1.7
Total Capacity at December 31 (MW)	88 951	85 511	4.0
hydro	51 512	50 007	3.0
nuclear	7 747	6 547	18.3
conventional thermal	29 691	28 957	2.5
Total net additions (MW)	3 440	1 469	134.2
hydro	1 505	608	147.5
nuclear	1 201	680	76.6
conventional thermal	734	181	305.5

* Excludes exchanges.
** Minor revisions from data reported in EPIC 82.

TABLE 4B.

PROVINCIAL ELECTRICITY SUPPLY AND DEMAND

Province	Year	Generation	Net Exports	Total Provincial Demand	Compound Annual Demand Growth 1982-83	1978-83	1973-83
		(GWh)	(GWh)	GWh)	(%)	(%)	(%)
Newfoundland	1983	39 992	31 233	8 759	3.20	-	-
	1982	44 264	35 777	8 487	-	2.91	4.79
Prince Edward Island	1983	11	520	531	3.91		
	1982	35	-	511	-	2.13	4.47
Nova Scotia	1983	6 168	-601	6 769	1.58		
	1982	6 581	-83	6 664	-	1.23	3.02
New Brunswick	1983	11 588	2 374	9 214	8.54		
	1982	8 394	-95	8 489	-	1.90	4.72
Quebec	1983	110 566	-11 799	122 365	3.75		
	1982	100 019	-17 918	117 937	-	2.17	4.06
Ontario	1983	117 818	5 561	112 257	5.59		
	1982	110 293	3 978	106 315	-	2.02	2.91
Manitoba	1983	22 084	7 317	14 767	2.79		
	1982	20 779	6 413	14 366		2.21	3.14
Saskatchewan	1983	10 353	-394	10 747	6.25		
	1982	9 843	-272	10 115		4.02	4.28
Alberta	1983	28 991	-151	29 142	6.01		
	1982	27 229	-260	27 489		8.80	7.90
British Columbia	1983	46 756	2 530	44 226	0.67		
	1982	48 238	4 307	43 931		1.98	2.79
Yukon	1983	676	-	676	-16.44		
	1982	809	-	809		4.7	.35
CANADA							
	1983	395 005	35 551	359 454	4.15	2.58	3.74
	1982	376 485	31 370	345 115			

Source: Statistics Canada

TABLE 5. TOTAL ELECTRICITY DEMAND IN CANADA BY SECTOR 1978-1982

	1978		1979		1980		1981		1982	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
Residential and Farm	86 106	27	87 638	27	92 669	27	95 048	28	99 248	29
Commercial	68 721	22	72 384	22	73 450	22	75 681	22	77 770	22
Industrial	161 608	51	163 443	51	173 949	51	175 526	50	168 421	49
TOTAL	316 435	100	323 465	100	340 068	100	346 255	100	345 439	100

Source: Statistics Canada. 57-202

FIGURE 1

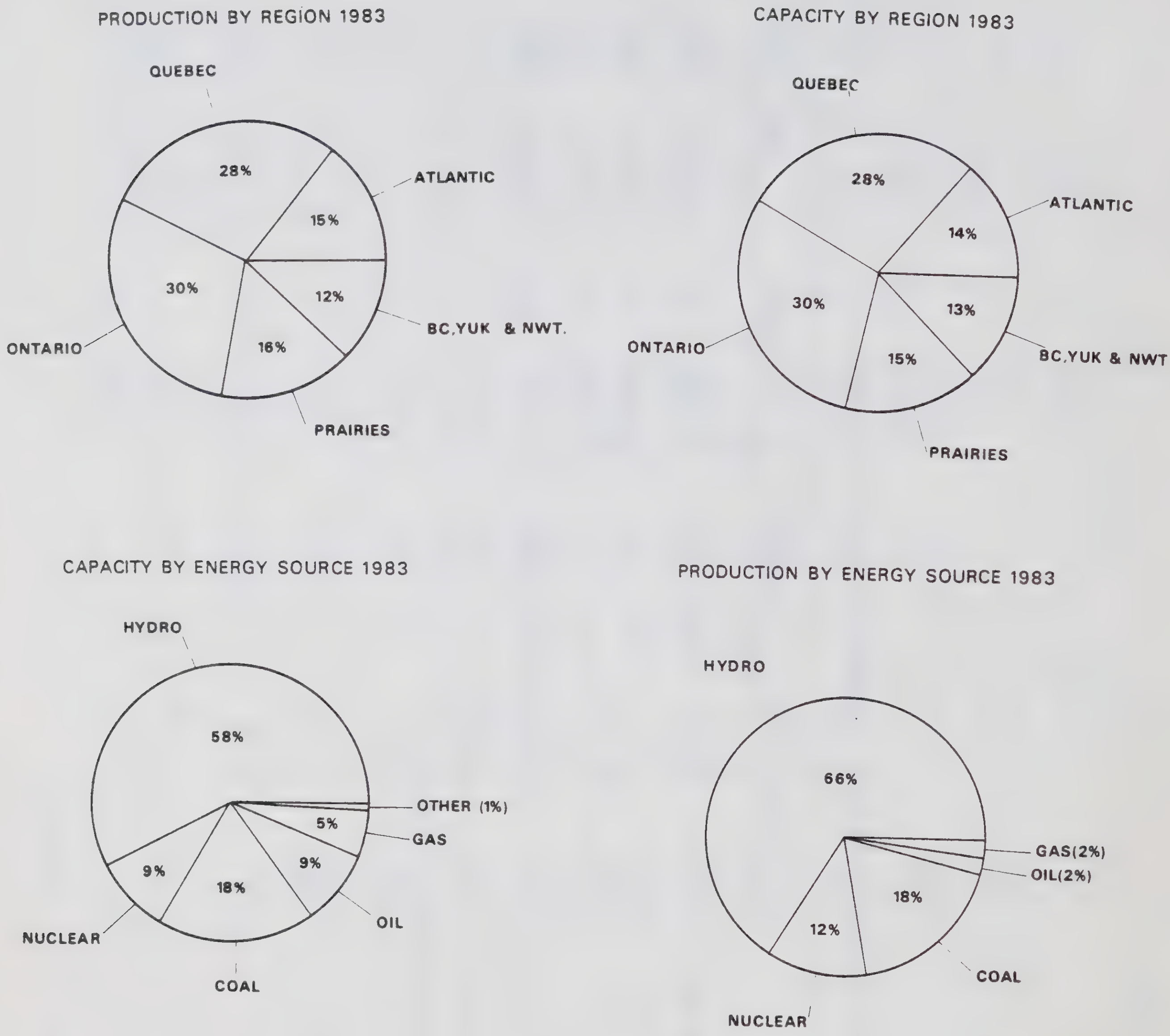

PRODUCTION BY REGION 1983
QUEBEC
28%
ATLANTIC
15%
12%
BC,YUK & NWT.
16%
PRAIRIES
30%
ONTARIO
CAPACITY BY REGION 1983
QUEBEC
28%
ATLANTIC
14%
13%
BC,YUK & NWT
15%
PRAIRIES
30%
ONTARIO
CAPACITY BY ENERGY SOURCE 1983
HYDRO
58%
OTHER (1%)
5%
GAS
9%
OIL
18%
COAL
9%
NUCLEAR
PRODUCTION BY ENERGY SOURCE 1983
HYDRO
66%
GAS(2%)
OIL(2%)
18%
COAL
12%
NUCLEAR

FIGURE 2A

INSTALLED CAPACITY BY PRINCIPAL FUEL TYPE
1983% OF PROVINCIAL TOTAL

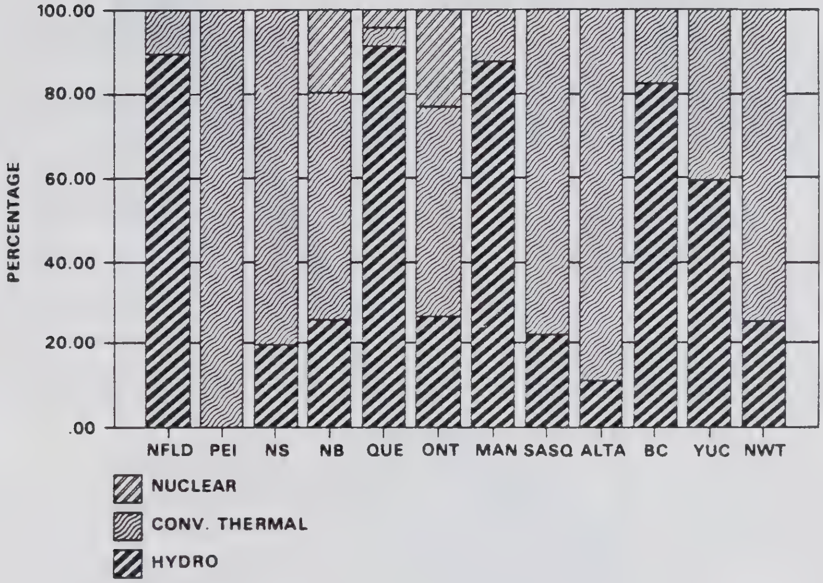


FIGURE 2B

ELECTRICAL ENERGY PRODUCTION BY PRINCIPAL
FUEL TYPE 1983 % OF PROVINCIAL TOTAL

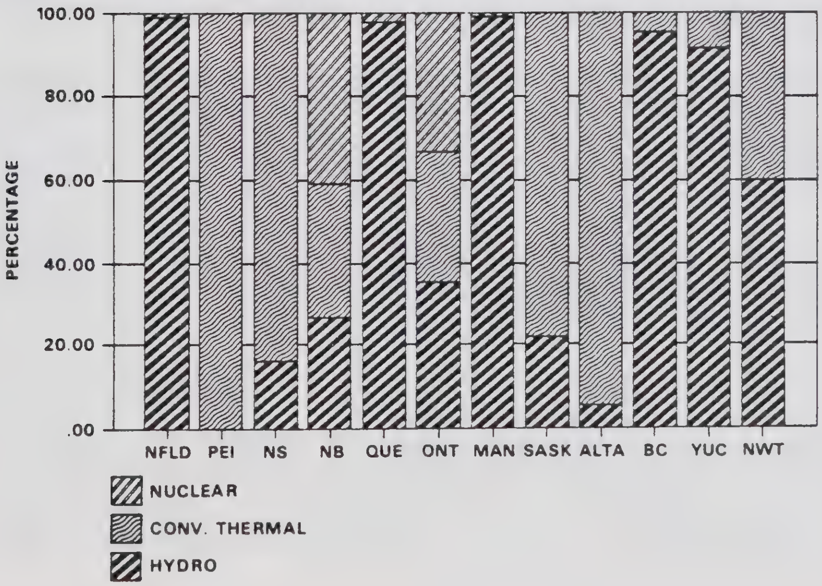


Figure 3

Historical Installed Capacity, 1917-1983

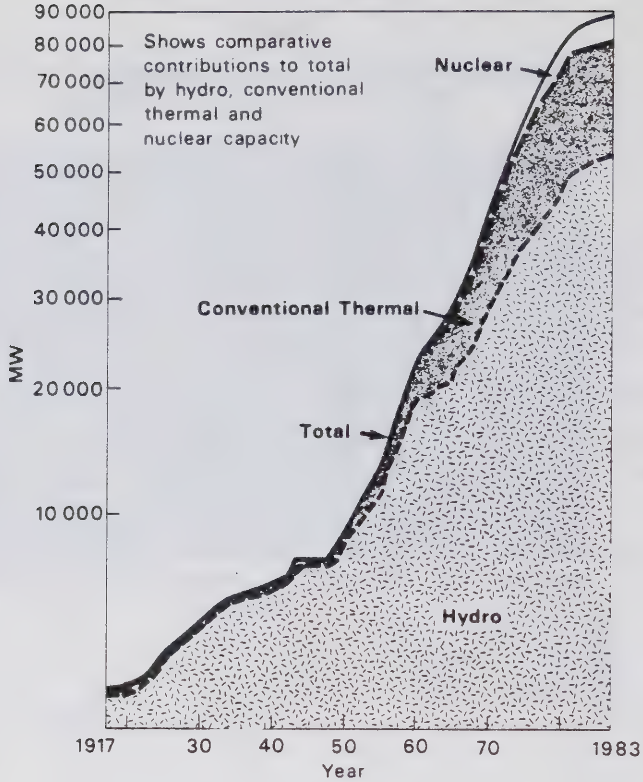


Table 6. Changes in Installed Capacity During 1983

Province	Project Name	Plant Type	Number of Units	Capacity (MW)
Additions				
Newfoundland	Upper Salmon	Hydro	1	84.00
	Lawn	Hydro	1	0.65
	Morris	Hydro	1	1.07
Nova Scotia	Fourth Lake	Hydro	1	2.50
	Lingan	Steam (coal)	1	150.00
Québec	Beauharnois (net)	Hydro	1	20.25
	Gentilly - 2	Nuclear	1	685.00
	LaGrande - 3	Hydro	7	1344.00
	Paugan (net)	Hydro	1	6.88
	Shawinigan - 3 (net)	Hydro	1	7.30
	Trenche (net)	Hydro	1	2.30
	Various Locations	Internal Combustion	N/A	3.90
Ontario	Bruce B	Gas Turbine	2	28.00
	Pickering B	Nuclear	1	540.00
	St. Mary's	Hydro	2	36.00
Saskatchewan	Poplar River	Steam (coal)	1	300.00
Alberta	Keephills	Steam (coal)	1	400.00
Northwest Territories	Various	Internal Combustion	N/A	1.80
Total additions				
No Deletions				3613.65

Source: Energy Mines and Resources - Utility Questionaire.

Developments in 1983

The following sections provide an overview of some of the more significant events relative to electricity supply and demand in Canada during 1983.

Federal Developments/Issues.

Activities which took place in some of the federal programs related to electricity suply and demand are outlined in the following sections.

The Role of Electricity in the Canada Oil Substitution Program (COSP)

The Canada Oil Substitution Program, implemented in May 1981, provides taxable federal grants of up to 50% of the cost of converting from oil to gas, electric or renewable energies for residential space heating, to a maximum of $800.

There were some 120,000 conversions of oil heating systems to electricity during 1983, mainly to the conventional baseboard type. This amounted to 44% of total conversions; by way of comparison 28% were to natural gas, 23% to wood, 1% to propane, and 4% to "other". These conversions to electricity were especially important in Quebec, where they accounted for some 69% of total provincial conversions, but were also important in New Brunswick (60%), Ontario (24%), and Manitoba (54%).

Electricity is forecast to play an important role in achieving the COSP off-oil objective, but the impact will not be so great as to require any major changes in current utility capacity expansion plans, nor to restrict exports of electricity to the United States.

The hybrid electric/oil heating system which involves retention of the existing oil heating system in order to supply heat during periods of peak demand on the electric power system and allows the use of electricity for space heating at non-peak times, received a great deal of attention during the year, especially in Quebec and in Ontario. Quebec offered very attractive financial terms for conversion from oil to the electric hybrid system in 1982 and continued with their program in 1983. Ontario introduced its promotional program for electric hybrid heating systems during 1983.

Coleson Cove Conversion

A three-stage study program to assess the feasibility of conversion of New Brunswick Power's 1000 MW Coleson Cove generating station from oil-firing to coal-firing began in January 1981. The study is funded through the National Energy Program's Utility Off-Oil Fund. Phases 1

and 2 of the study were completed by the end of 1982. A study committee has recommended proceeding with the final phase of the project and it is expected to be carried out in 1984.

EMR Energy Forecast

1983 marked another year of sharp reductions in long-range electricity demand forecast for some utilities. For example, average annual growth for the period 1983 to the year 2000 was reduced by B.C. Hydro to 3.5% from the previous forecast of 4.0%; in Alberta the utilities' forecast was reduced from 5.5% previously, to 4.1%, and Hydro Quebec reduced its forecast from 4.0% to 3.1%. Overall, the reduced major utility forecasts resulted in a national electricity demand forecast from 1983 to 2000 of 2.9% compound annual growth compared to last year's forecast of 3.5%.

This year also marked the first time in several years that the Department of Energy, Mines and Resources (EMR) forecast a higher rate of electricity demand growth than did the utilities. The EMR long range forecast to 2000 prepared in July 1983 was for average annual growth of 4.0% per year, compared to the forecast of 2.7% per year based on the utilities' forecast (the major utility forecasts are combined with forecasts prepared by the National Energy Board for minor utilities and industries which produce electricity to achieve provincial totals equivalent to the EMR forecasts. The forecasts by the major utilities make up about 87% of the provincial total). The two forecasts diverge to some extent for the remainder of the 1980's: 3.5% annual growth forecast by EMR compared to 2.9% for the utility-based forecast. However the forecast growth during the 1990's was very different: EMR forecast 4.4% annual growth while the utility-based forecast was for 2.6%. By the year 2000, the EMR forecast is for total electricity demand of about 700 TWh, versus about 575 TWh for the utility-based forecast.

Electricity demand has been historically very highly correlated to economic performance. Electricity intensity in the Canadian economy, i.e. the amount of electricity used for each dollar of real gross national product (GNP), has been steadily increasing over time. This was true even during the very turbulent period from 1974 to the present. Based on the economic growth forecast used in the EMR electricity demand forecast (3.1% real, i.e. net of inflation, annually to 2000), electricity intensity continues to increase at about the historical rate, from 2.70 kWh/$GNP (1971 $) in 1983 to 3.15 in 2000. This seems reasonable, since Canada has low cost electricity relative to other parts of the world. However, utility based forecasts result in decreasing electricity intensity, based on the economic growth forecast used in the EMR forecast, from 2.70 kWh/$GNP in 1983 to 2.59 in 2000. In assessing the reasonableness of such a forecast, it is necessary to question what factors would cause this change in a long-term trend, and whether such a change is reasonable in the Canadian situation.

This differing perception in the demand for electricity during the 1990's could result in inadequate capacity in that period, if the EMR forecast turns out to be more accurate than that of the utilities. However, it could be that the utility forecasts have reached a low point for this cycle, and the forecasts will tend to increase as demand picks up. Utility forecasts tend to be reduced during periods of slow growth, and to increase during periods of more robust growth. Electricity demand has picked up in many areas of the country during the economic recovery experienced during 1983, particularly during the period from May to the end of the year. (See the section on Consumption, Production and Capacity.) It is entirely possible that the utility forecasts will now tend to increase as this new information is assimilated into the forecasting process. Given this inevitable uncertainty, electric utility planners and those bodies approving siting and expansion plans must seek to provide for maximum flexibility so that the twin evils of surplus and shortage are avoided. The increasing "lead time" for project approval and construction is making such flexibility increasingly difficult to achieve.

Part of the reason why electricity demand has been much less than was forecast over recent years is that our economic performance has been much worse than forecast. Similarly, the magnitude of future electricity demand will depend critically on the level of economic performance, something that has proven to be very difficult to predict with a high degree of accuracy. Further work needs to be done to explain differences between the several forecasts which may result from a combination of methodology differences and ranges of assumptions on prices and other economic variables.

Provincial Developments/Issues

Exports

There were few new export licences issued by the National Energy Board during the year. Perhaps the most significant was that issued to New Brunswick Power for 100 megawatts of capacity from its system until October 1984 and 150 megawatts thereafter until 1991, rather than from a specific plant.

Late in the year the National Energy Board held its hearing on Hydro Quebec's application for a licence to export 111 TWh of interruptible energy over the period 1984 to 2002 to the Power Authority of the State of New York. There is provision in the license package for conversion of part of this export into firm licences. The new Chateauguay high voltage direct current (HVDC) converter station which is expected to be in operation in 1984 will facilitate these exports. (A decision on that application was announced in March/84; it approved most of the annual energy exports requested but for a shorter time period.)

Electric Utility Marketing Programs

During the 1960's, marginal costs were well below average costs as a result of economies of larger scale generating units, advances in generation and transmission technology and low inflation rates, so increased sales meant increased capacity and lower prices for all utility customers. Utility managers used vigorous marketing at that time, such as promotional pricing, to increase energy sales.

The 1970's was a different story however. Inflationary forces which had been building during the 1960's reached full bloom in the 1970's: world oil prices increased five-fold from January, 1973 to 1975 and tripled again by 1980, for a 16-fold increase between 1972 and 1980; interest rates exploded upwards - utility bond interest rates went from an average of 8.4% in 1972 to 16.3% in 1981 (reaching a peak of 19.2% in Sept./81) - and construction costs escalated rapidly. The effect of these forces on a capital intensive industry such as electric utilities was to rapidly increase marginal costs of supply above average costs. In that environment it made sense to avoid promotion of sales of electricity that would require adding new capacity and cause prices to escalate more quickly, so sale activities of utility marketing groups were reduced or eliminated.

The present situation and that in prospect for the rest of the 1980's is different from both the 1960's and 1970's. Electricity demand turned out to be much lower than that forecast for a variety of reasons, including much poorer economic performance than was forecast, conservation resulting from rapid energy price increases, and abnormally mild winters. As a result many utilities now have, and expect to have for the near future, excess electricity supply capacity. It now makes sense to attempt to sell excess capacity and energy to generate additional revenues, as some utilities have started to do.

The three most active utilities in this regard are Ontario, Quebec and B.C. Ontario Hydro has set up a new marketing group, which will base its marketing approach on the following:

- Ontario Hydro will have enough generating capacity for this century without adding new capacity after Darlington, even if load grows during the 80's at 4%, much higher than the presently forecast 2.4%.

- the focus will be on off-peak energy sales

- load management techniques will be developed to help limit future capacity needs

- time-of-use rates will be introduced.

Specific marketing programs include the hybrid heating system for residential space heating.

Hydro Quebec has taken an aggressive approach to selling surplus energy both in Canada and the U.S. The utility has developed four objectives for its marketing programs, as follows:

1. During the next few years, to establish prices and sales conditions which will consolidate electricity's current position in the province's energy supply and to increase its market penetration by providing energy requirements to customers at a rate lower than alternative supplies.

2. Establish commercial programs which will result in additional sales of firm energy of 1.5 TWh in 1984, 3.3 TWh in 1985 and 3.5 TWh in 1986 as well as additional sales of interruptible energy of 7.3 TWh in 1984, 9.9 TWh in 1985 and 1986.

   Programs to achieve this will include the following:

   (a) hybrid heating program for the residential sector, including financial grants;

   (b) extension of the hybrid heating program to the commercial sector and to institutions in 1984;

   (c) a program to install electric boilers for industry to displace other fuels, especially heavy oil;

   (d) a program of rate rebates to industrial customers for additional power taken, which will result in additional investments by both existing industries and new industrial customers.

3. Develop new applications for electricity in the commercial and industrial sectors.

   Programs to accomplish this include the following:

   (a) reviewing the operations of large companies to identify electrical technologies applicable to process industries, especially pulp and peper, mining, textiles, food processing and smelting.

   (b) reviewing the uses of electricity in the industrial and commercial sectors to better understand the energy needs of customers in these sectors.

4. Obtain the greatest possible revenue from sales to neighboring utilities.

   The 1000 MW Chateauguay HVDC converter station to be completed in 1984 will facilitate exports to Ontario as well as to New York. Agreement has been reached to double exports to New Brunswick by 1985 by adding new interconnection facilities. Negotiations are taking place with the New England Power Pool for sale of 2000 MW, including the 690 MW for which agreement was reached in 1982, subject to regulatory approval.

B.C. Hydro's marketing program also encompasses active attempts to export as well as to increase sales in the province. In the fall of 1983 the utility agreed to sell to Los Angeles and three adjacent cities for three years a total of 3000 GWh, an amount equal to one-half of its firm energy surpluses, subject to regulatory approval and appropriate transmission arrangements with intervening utilities. For in-province sales the utility is offering reduced rates to large industrial customers for purchases above normal use.

Nuclear Power Developments

1983 was a year of considerable significance to the Canadian nuclear industry. Nuclear generation increased sharply. Four units of the new CANDU 600 series were put into service - two in Canada and two abroad - and one larger unit was added in Ontario. However, serious problems developed in one of the older Ontario nuclear units in the form of ruptured pressure tubes, as outlined in the following section entitled "Pressure Tube Problems".

Increased Generation

Nuclear generation in Canada amounted to 46,221 GWh in 1983, an increase of 28% from 1982; it amounted to 12% of total generation.

New Units

New Brunswick Power's Lepreau unit (680 MW) came into operation in late 1982 and was declared in commercial service in January 1983, and Hydro Quebec's Gentilly 2 (685 MW) unit was put in service in September. The operating performance of the Lepreau unit is particularly noteworthy. Although it reached full power only at the end of March, its average capacity factor since its in-service date was 87%; in five of the eleven months of service the capacity factor was over 98%. N.B. Power has stated that the cost/MWh from the Lepreau unit operating at these high capacity factors (including capital-related charges, operating costs and fuel costs plus allowances for disposing of spent fuel and decommissioning the plant) is less than the cost of fuel alone at its most efficient oil-fired generating stations. This is quite a remarkable result given the high early-year costs typical of capital intensive nuclear plants as well as the decline in oil prices.

The same size unit as those installed at Lepreau and Gentilly was also placed in service in South Korea and Argentina. These plants, like the two Canadian units, proved easy to start up and operate. The Korean unit had problems with steam separators which adversely affected its early performance but since August it has performed very well. The Korean reactor was put into service in just 65 months (from first concrete to full power), much faster than typical world experience for nuclear reactors.

Ontario Hydro's Pickering 5 (540 MW gross) unit was placed in service in May, and early indications are that it will perform as well as the earlier units. It had a capacity factor of 92% for the seven-plus months that it was in service in 1983.

Pressure Tube Problem

In August, one of the 390 zircaloy-2 pressure tubes in Ontario Hydro's Pickering unit 2 ruptured unexpectedly with no prior leakage or other indication of an impending problem. The tube had been in service for 12 years. Following the tube failure, the reactor was shut down by the station operator in a controlled manner without using fast shutdown systems. No emergency cooling systems had to be used.

The rupture was apparently the result of cracks which formed on blisters that developed on the hot pressure tube when it came in contact with the cold calandria tube which houses the pressure tube. Dislocation of spring spacers between the pressure tubes allowed the pressure tube to touch the calandria tube. Pickering unit 2 has been out of operation since the pressure tube rupture in August; Pickering unit 1 has been shut down since November because examination showed similar deterioration of a number of tubes.

Ontario Hydro has decided to replace the pressure tubes in the two reactors, starting in the spring of 1984, at an estimated cost of $700 million, including $400 million for coal used in coal-fired plants to replace the energy from the nuclear units. The units will be out of service for up to three years. The remaining CANDU units at Pickering and Bruce use zirconium-niobium for the pressure tubes and are therefore unlikely to suffer this type of failure.

Even with the outages of Pickering units 1 and 2, the capacity factor for the four-unit plant in 1983 was 77%, still a fine performance. The four-unit Bruce station had a capacity factor of better than 90% in 1983, giving all Ontario Hydro nuclear units a combined capacity factor of 83%, well above the world average. Pickering unit 5, which was put in service in the spring of 1983, had the best performance record among the nuclear units, 92% capacity factor.

There are some positive aspects of the pressure tube problems at Pickering. One is the demonstrated safety of the CANDU design, which enables the unit to suffer a significant material failure and still shut down by normal methods, i.e. without using emergency procedures, and without any adverse health consequences. The problems are also ameliorated by the fact that it had been considered probable for some time that the tubes would have to be replaced.

Churchill Falls Dispute

There was action on all three aspects of the litigation currently underway between Quebec and Newfoundland regarding the power contract signed in 1969 by which Hydro Quebec purchases about 90% of the output of the 5225 MW Churchill Falls hydro electric plant in Newfoundland until 2041, at a price of $2 to $3 per megawatt-hour.

First, in June 1983, the Trial Division of the Newfoundland Supreme Court ruled that Newfoundland does not have the right to recall the 800 MW which it sought from Churchill Falls. Newfoundland appealed the decision to the Appeal Division of the Provincial Supreme Court. Second, in August 1983, the Quebec Superior Court ruled that Hydro Quebec could claim damages against Churchill Falls (Labrador) Corporation (CFLCo.) if the company delivered the 800 MW which Newfoundland had tried to recall. Third, in September 1983, the Supreme Court of Canada announced that it would delay until December 31, 1983 delivery of its decision on the constitutional validity of Newfoundland's Water Rights Reversion Act, by which Newfoundland would, in effect, expropriate the Churchill Falls project. The case was heard before the Supreme Court in September and October of 1982. The Court delayed its decision at the request of the parties involved to permit the two provinces to attempt to reach a negotiated settlement of the issue. In December 1983, the Court again agreed to delay its decision until March 31, 1984 to allow more time for negotiation.

In March, 1984 Hydro Quebec proposed amendments to the power contract; Newfoundland rejected these, and stated that it would await the Supreme Court ruling before continuing the negotiations. On May 3rd 1984 the Supreme Court released its unanimous judgement that Newfoundland acted beyond its constitutional authority in enacting the Water Rights Reversion Act legislation.

Rail Electrification

Canada's first major rail electrification project was put into service in 1983. British Columbia Railway is testing the first two of seven 50 kV electric locomotives on a newly built 130 km line in northeastern British Columbia, running between the coal fields in the northeast and the main line which connects to the new deep-sea terminal being constructed at Ridley Island, near Prince Rupert. Construction of the project, which cost $450 million, started in 1981 and the first load of coal moved over the line in November, 1983, one month ahead of schedule. Two major tunnels had to be built on the line, one six kilometres long and the other nine kilometres long; these tunnels were the major reasons why BC Rail decided in mid-1982 to go the electrification route. This approach avoided the need for extensive and expensive ventilation work in the tunnels for heat dissipation, which would have cost nearly $15 million had diesel electric power been used.

Seven 6,000 hp electric locomotives will be used instead of eleven diesel/electrics at 3500 hp. While the capital cost of the electric locomotives is 50% higher than diesel/electric locomotives, they deliver more power per axle. Another factor in their favour is that electrification reduces maintenance costs by over one-third and reduces energy costs by as much as two-thirds. The higher capital cost of the electric locomotives is substantially offset by the fact that they last about twice as long as the diesel/electrics. This

project could lead to further electrification of B.C. Railway and the experience may have application to other Canadian rail systems and to off-shore projects.

Annapolis Tidal Project

Construction of a low head 20 MW hydro demonstration project located in the tidal part of the Annapolis River at Annapolis Royal, N.S. started in 1980. The Department of Energy, Mines and Resources has provided $25 million toward the cost of the project, now estimated to be about $57 million. The project is expected to provide information on the operation of a single-stage tidal power project and on the cost-effectiveness of a new type of low head turbine for river and tidal applications.

The project was halted about three months from completion by an electrician's strike in the spring of 1983. Work resumed in the late fall, and the project started generating electricity for the grid in May, 1984.

Mothballed Plants

The current excess generating capacity being experienced by several utilities has led to some plants being mothballed. This means that the equipment is shut down and carefully protected to reduce deterioration. The units would be available for subsequent use but only after a significant period of re-commissioning. In the meantime costs of supervision and maintenance are substantially reduced. In 1983 Ontario Hydro mothballed 3 coal-fired units (581 MW) at the R.L. Hearn plant, and 2 coal-fired units (128 MW) at the J.C. Keith plant. Saskatchewan Power mothballed its A.L. Cole thermal plant (90 MW) in 1983.

The utility where mothballing has been most extensive is Ontario Hydro; it is the Canadian utility with the most older fossil-fuelled plants. A chronological sequence is provided below:

Hearn: Five units in 1979 and 1980 (the remaining 3 units were mothballed in 1983)

Lennox: Two units of this oil-fired station in 1980 and the other two in 1982.

The following further mothballing is expected in 1984:

J.C. Keith: The two remaining units (two were mothballed in 1983).

Lakeview: Two 300 MW units.

In addition, the Atikokan (206 MW) coal-fired station may be mothballed as soon as it has been commissioned in 1984.

By the end of 1983, mothballed generation capacity at Ontario Hydro totalled 3783 MW .

This will leave the coal-fired plants at Nanticoke (4000 MW), Lambton (2000 MW) and Thunder Bay (447 MW) as the fossil-fired steam plants in operation for Ontario Hydro.

Skagit Valley

The International Joint Commission (IJC) in 1942 gave authority to the city of Seattle to raise the height of the existing Ross Dam on the Skagit River in Washington State to enable generation of additional electricity. The increased level of the reservoir would result in flooding of the Skagit Valley in British Columbia. The B.C. government of that time accepted this action, and indeed later accepted payments from Seattle as compensation for the proposed flooding. Since then, as a result of re-assessment of the scenic and recreational benefits of the Skagit Valley and the adverse environmental impact that flooding would have, the B.C. government - supported by the federal government - has sought to prevent flooding. Seattle is content to do this, providing it receives suitable compensation for lost benefits.

B.C. and Seattle now have agreed in principle to an 80-year agreement whereby B.C. will provide to Seattle an amount of power and energy equivalent to that which it would have realized from raising Ross Dam, at a cost equivalent to that which it would have incurred by increasing the generation of the Ross Dam. The agreement will also provide for the establishment of an environmental endowment fund to manage and develop the Ross Dam/Skagit Valley area for recreational and envrionmental conservation purposes. The period of the agreement is 1986 to 2066. The amount of energy included in the agreement is about 330 GWh annually as measured at the Skagit plant; maximum capacity is 150 MW at the Skagit plant during the months of April through October, and 532 MW minus the actual operating capacity of the existing Ross Dam at the Skagit plant during the remaining part of the year. A Canada-US treaty and special Canadian legislation is in preparation to implement this agreement, as is a Canada-British Columbia agreement.

EXPORTS AND IMPORTS

International Trade

Net electricity exports to the United States in 1983 increased by 12% relative to 1982, to 35,551 GWh, resulting from exports of 38,308 GWh and imports of 2757 GWh. Revenue increased by 13%, to $1 249 million. Table 7 provides information on electricity exports and imports, costs and revenue, as well as sources of generation for exports for the period. About 80% of electricity exported is interruptible, i.e. it is available only when it is surplus to the selling utility's needs, and is used to displace the purchasing utility's higher priced generation.

More information on exports and imports by province is provided in Table A5 and Figure 4.

Table 7. International Electricity Trade, 1977-1983.

	1977	1978	1979	1980	1981	1982	1983
				(GWh)			
Exports[a]	18 509	20 542	30 491	28 229	34 730	32 986	36,907
Imports[a]	1 060	185	24	169	466	268	211
Net Exports	17 449	20 357	30 467	28 060	34 264	32 718	36,686
Type of Exports (b)							
Firm	3 727	3 981	6 692	7 236	5 008	5 829	10,218
Interruptible	14 782	10 561	23 799	20 993	29 722	27 157	26 689
Total	18 509	23 542	30 491	28 229	34 730	32 986	36 907
Generation source for exports:[c]							
Hydro	5 738	6 984	14 941	12 336	19 948	18 574	19 237
Imported Coal	8 514	10 476	11 587	10 599	10 901	10 315	11 704
Imported Oil	2 961	2 260	3 354	2 867	1 940	1 959	1 201
Canadian Fossil Fuels: (coal/oil)	555	411	128	593	665	502	519
Nuclear	--	--	177	30	42	96	1 856
Other[d]	740	411	305	1 804	1 234	1 540	2 390
Total	18 509	20 542	30 491	28 229	34 730	32 986	36 907
Revenue/Cost			(million $)				
Exports	419.27	478.55	738.51	793.58	1143.87	1105.90	1249.00
Imports	13.13	1.76	0.70	2.94	5.62	5.41	5.80
Net Revenue	406.14	476.79	737.81	790.64	1138.25	1100.49	1243.20

(a) Excludes no-valanges.
(b) Firm exports reenergy that must be made available when the purchaser wants iterruptible exports refer to energy that is made available bsupplier only when surplus energy exists. Firm energy often com higher price than interruptible energy, to reflect its greaue to the purchaser.
(c) Estimated from dmajor utilities.
(d) Includes purchasexport where the generation source is not identifiable.

Source: National Eneard

The provincial sourcexports and revenue/GWh received since 1981 are as follows:

Table 8A: Provinciaes of Export Revenue/Gwh 1981-1983.

			1982		1983		
	Expo	venue	Exports	Revenue	Exports	% Change	Revenue
	GWh	MWh	GWh	$/MWh	GWh	From 82 %	$/MWh
New Brunswick	3 25.6		2 989	53.2	5 311	78	51.2
Quebec	8 33.6		8 535	34.3	10,225	20	33.2
Ontario	11 52.7		11,136	38.6	12,279	10	37.5
Manitoba	3 57.2		5 217	14.8	5 967	14	14.9
Saskatchewan	-		42	36.8	61	45	26.8
British Columbia	8 06.8		5 064	28.6	3 161	-38	25.6

The reason for the majoease in exports from New Brunswick in 1983 was the start in Februadelivery of 205 MW from the 640 MW net Lepreau nuclear plant; exports were increased by a further 25 MW in July. Quebec experiencenificantly increased exports as a result of greater surpluses availand improved demand in the U.S. Increased exports from Manitoba re from better water conditions in the province, allowing greatro generation. Exports from British Columbia declined signify in 1983 for the second straight year; in 1982, exports declined b from 8821 TWh. The major cause of this decline is the much greaailability of hydro generation in the U.S. Pacific northwest, combith the reduced rate of electricity demand growth in that region.

The energy sources of provincial exports for 1983 are as follows (% of total for each province):

Table 8B: Energy Sources of Provincial Exports 1983.

	Oil	Coal	Nuclear	Hydro	Other	Total
New Brunswick	24.5	9.0	35.0	-	31.5	100
Quebec	-	-	-	100.0	-	100
Ontario	-	99.0	1.0	-	-	100
Manitoba	-	2.0	-	98.0	-	100
Saskatchewan	-	100.0	-	-	-	100
British Columbia	-	-	-	100.0	-	100

The markets for exports from each province, and type of fuel displaced, are as follows for 1983:

Exporting Province	Importing States	Fuel Displaced
New Brunswick	New England	Oil
Quebec	New England	Oil
	New York	Oil, coal
Ontario	New York	Oil, coal
	Michigan	Coal
	Wisconsin	Coal
Manitoba	North Dakota	Coal
	Minnesota	Coal
Saskatchewan	North Dakota	Coal
British Columbia	California	Oil, coal, gas

The differences in the unit revenue received for exports by the various provinces are covered by three main factors:

1. The energy source of the electricity exported.

2. The energy source of the electricity displaced by imported electricity.

3. Whether or not the exporting utility has direct transmission access to the importing utility.

Some 80% of all exports are interruptible and are used to displace the buyer's higher cost generation. The price of interruptible energy is some percentage (usually 50% but sometimes as much as 80%) of the sum of the buyer's and seller's variable cost of producing the energy. The unit revenue received for energy produced from hydro for which the variable production cost is very low-will be much lower than that received from energy produced by thermal. The most costly form of thermal generation is oil, followed by eastern then western coal. Nuclear generation has the lowest variable cost.

Transmission access to markets is also an important determinant of revenue since a price must be paid to use lines to transmit energy from the seller to the buyer. Since the buying utility has a fixed price that it is willing to pay for energy, any intervening transmission costs must be borne by the seller, resulting in lower unit revenue at the border.

The foregoing factors in this section indicate that New Brunswick and Quebec enjoy the most advantageous market, since their energy is displacing oil-fired generation and they have direct access to the market. Manitoba energy displaces western coal-fired generation and there is not always direct transmission access to the market. British Columbia also faces significant transmission wheeling costs.

The provincial composition of exports since 1981 has been as follows (% of total exports):

Table 8C: Provincial Composition of Exports.

	1981	1982	1983
New Brunswick	10	11	14
Quebec	24	25	28
Ontario	33	33	33
Manitoba	10	16	16
British Columbia	23	15	9
	100	100	100

Exports from Manitoba and British Columbia tend to fluctuate to a greater extent than those of the other exporting provinces. This is because their systems are almost entirely hydro, so water availability is a very large factor in determining how much energy is available for export. Also, transmission capacity between these provinces and their potential markets is not always available.

The amount of electricity exported and the revenue received are expected to continue to increase over the coming decade, as they have for the past several years. Canadian electricity, generated primarily from hydro and coal, will be used increasingly to displace higher-cost fossil-fired generation in the U.S. The small amount of oil-fired export from New Brunswick results primarily from a contract negotiated with New England utilities prior to the major oil-price increase. This contract ends in 1986.

Hydro-generated exports are expected to increase relative to total exports, nuclear exports to increase, coal-fired exports to decrease and oil-fired exports to be almost eliminated after 1986.

There are approximately 30 Canada - U.S. interconnections of 69 KV or over, with power transfer capacity of approximately 10,000 MW. There were no additions to these interconnections in 1983. Planned additional or upgraded interconnections are indicated in Table 11.

Some of the more significant events of 1983 in electricity exports to the U.S. were as follows:

(a) New Brunswick Electric started firm exports of 205 MW from the Lepreau nuclear plant in February, the first firm exports from a Canadian nuclear plant. These exports were increased to 230 MW in July.

(b) New Brunswick Power received National Energy Board (NEB) approval to export 100 MW of system power to Maine.

(c) Hydro Quebec received NEB approval for exports to New York, consisting of about 24 TWh annually of interruptible energy from 1984 to 2002. Hydro Quebec announced in the spring of 1984 that it had signed a letter of intent to sell 150 MW of firm power to Vermont from 1985 to 1995. The power has a value of about $500 million (US) and requires NEB approval. It is Hydro Quebec's first export of firm, long-term power. Hydro Quebec is negotiating with New England utilities to increase its exports of 690 MW to 2000 MW, starting in 1985.

(d) B.C. Hydro negotiated exports of 6 500 GWh to Los Angeles and some surrounding cities. Exports started in November, 1983 under existing export licences. However, NEB approval is being sought to extend these licences and increase the amount of energy that can be transmitted.

B.C. Hydro has received provincial government approval to seek exports of firm power; previous exports have all been of the interruptible kind. With Quebec's declaration in 1982 that it would be seeking firm export contracts, the B.C. decision means that all Canadian exporting provinces are now seeking contracts for firm as well as interruptible energy.

(e) Atomic Energy of Canada and New Brunswick Power established Maritime Nuclear Limited with offices in Fredericton, N.B. to investigate the feasibility of building a second CANDU 680 MW nuclear unit at Point Lepreau, primarily for export.

(f) Manitoba Hydro participated with Wisconsin utilities in a study to assess the feasibility of the U.S. utilities importing additional amounts of power and held talks with other mid-Western utilities concerning new power exports.

Interprovincial Trade

The only significant change in interprovincial transfers during 1983 was the nearly eight-fold increase in net exports from New Brunswick to Nova Scotia, from 83 GWh in 1982 to 600 GWh in 1983. With the availability of energy from the Lepreau nuclear plant, New Brunswick Power could not use all of the imported power from Quebec to displace generation from fossil fuel, and so much more of it was passed on to Nova Scotia.

A temporary 138 kV radial interconnection constructed during the year will permit New Brunswick to import an additional 75 MW from Quebec. By 1985 permanent facilities are expected to be in place to permit transfer of 500 MW in addition to the existing 350 MW interconnection.

There were no additions to the existing interprovincial interconnections given in Table 12A. Proposed interprovincial interconnections are indicated in Table 12B.

TABLE 9. MAJOR[1] INTERCONNECTIONS BETWEEN CANADA AND THE UNITED STATES

Province	State	Voltage	Power Transfer Capability
		(kV)	(MW)
New Brunswick	Maine	345	600
Québec	New York	765	1400
	New York	2 x 120	200
Ontario[2]	New York	230	470
		230	400
		2 x 230	600
		2 x 345	2300
	Michigan	230	535
		230	515
		345	710
		345	760
Saskatchewan	North Dakota	230	150
Manitoba	North Dakota	230	150
	Minnesota	230	175
	Minnesota	500	1000
British Columbia	Washington	230	350
		230	300
		2 x 500	1400

1. 100 MW capacity or over.
2. The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

Source: Energy Mines and Resources - Utility Questionaire.

TABLE 10. PLANNED INTERCONNECTIONS TO THE UNITED STATES

Province	State	Completion date	Voltage	Estimated power transfer capability
			(kV)	(MW)
1				
Quebec (a)	New England	1986	450 DC	690
Manitoba (b)	Nabraska	1988	± 450 DC/500 AC	1 000

(a) Proposed
(b) Under serious review

In addition, Quebec expects to have a high-voltage direct current converter station at Châteauguay with a transfer capability of 1000 MW in service in 1984.

Source: Energy Mines and Resources - Utility Questionaire.

TABLE 11A. EXISTING PROVINCIAL INTERCONNECTIONS

Connection	Voltage	Capability	
		Installed	Firm
	(kV)	(MW)	
British Columbia-Alberta	1 x 138	110	80
Saskatchewan-Manitoba	3 x 230	400	400
Manitoba-Ontario	2 x 230 1 x 115	260	260
Québec-Ontario	4 x 230 9 x 120	1 300	1 300
Québec-Newfoundland	3 x 735	5 225	4 300
New Brunswick-Quebec	± 80 (DC)	350	350
New Brunswick-Nova Scotia	2 x 138 1 X 345	600	600
New Brunswick-Prince Edward Island	1 x 138	200	100

Source: Energy Mines and Resources.

TABLE 11B. PROPOSED PROVINCIAL INTERCONNECTIONS

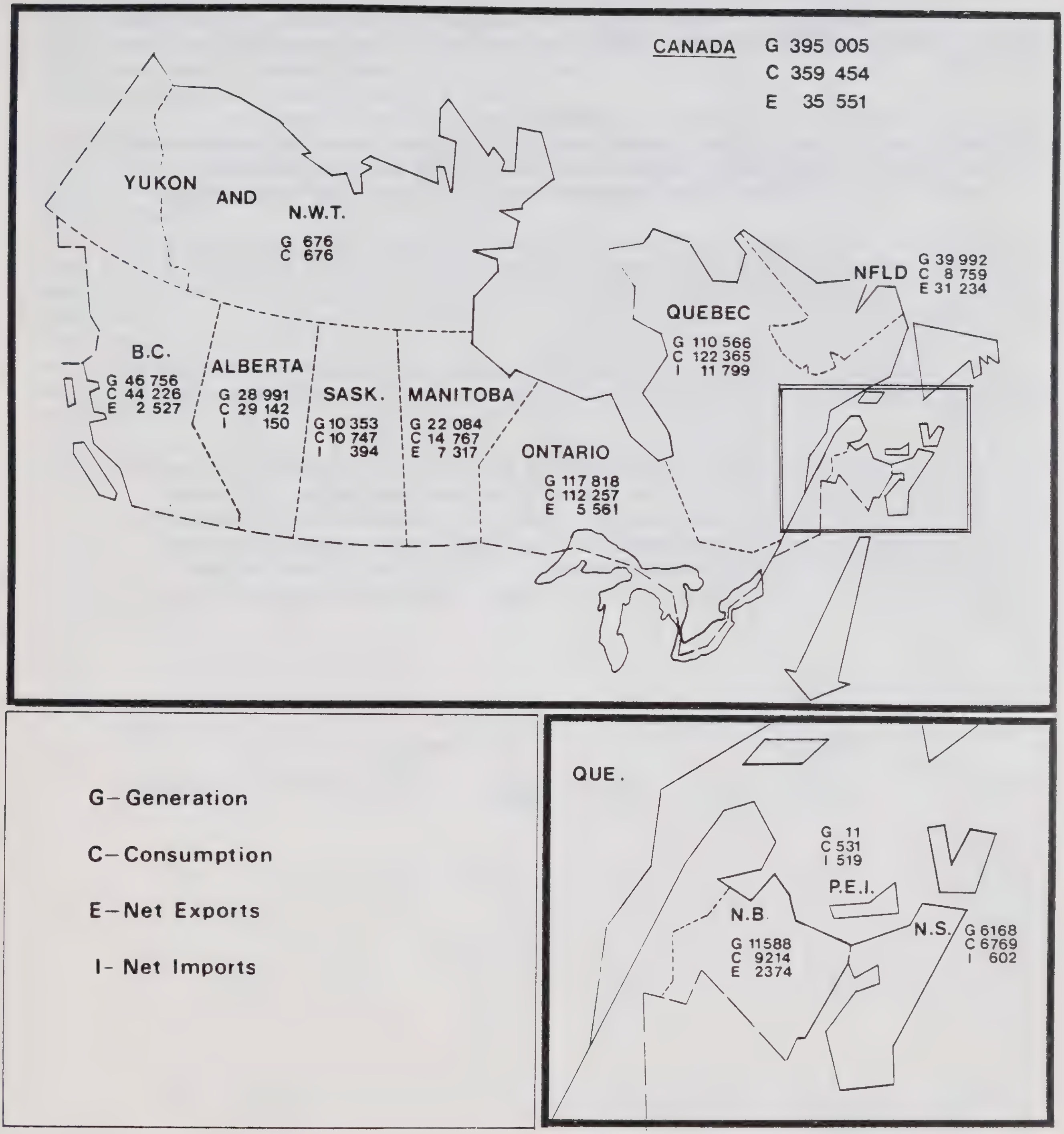
Province Installed	Connections (kV)	Year	Capability: Installed (MW)	Capability: Firm (MW)
British Columbia-Alberta[a]	500 (AC)	1985	800	600
Québec-New Brunswick[a]	130 (DC)	1985	500	500

(a) Under construction

Source: Energy Mines and Resources - Utility Questionaire.

Figure 4

Electric Energy, Net Transfers and Exports, 1983 (GWh)



FUEL USE

Electricity production from fossil fuels increased by 2.4% in 1983 over 1982. The fossil fuel share of total electricity production was 22%, the same as last year. The production of electricity from coal increased by 10%, that from oil decreased by 26%, and that from gas decreased by 22%.

The major increases in coal-fired production were in Alberta (24%), Nova Scotia (18%) and Saskatchewan (15%); production in New Brunswick declined by 23%.

Oil-fired production declined in Newfoundland (40% as a result of increased hydro production), Nova Scotia (32% as a result of displacement by coal-fired production), and New Brunswick (35% as a result of increased hydro imports from Quebec and increased nuclear production).

Natural gas is used for electricity production primarily in Alberta and Ontario. Production in Alberta declined by 33%; it declined by 10% in Ontario. The Ontario natural gas is used mostly in industrial co-generation plants.

Nuclear production increased by 27%: 8% in Ontario and the rest in Quebec and New Brunswick as a result of placing their first nuclear reactors in service.

Table 12 provides information on utility use of fuels in 1982, the most recent year for which Statistics Canada data are available. It shows that Ontario was the largest user of fuels for electricity production in 1982, accounting for approximately 61% of the total. Alberta was the second largest user, accounting for 21%. New Brunswick remains the largest user of oil, but much of it is used to generate electricity for export.

TABLE 12. FUEL USED BY UTILITIES 1982.

	Natural Units				Energy Content (10^3 TJ)					
Province	Coal (10^3 tonnes)	Oil (10^3 m^3)	Gas (10^6 m^3)	Uranium (10^6 Grams)	Coal	Oil	Gas	Uranium	Total	(%) of Total
Newfoundland	-	336	-	-	-	14	-	-	14	1.1
Prince Edward Island	-	19	-	-	-	1	-	-	1	0.1
Nova Scotia	1 300	494	-	-	35	21	-	-	56	4.4
New Brunswick	548	966	-	5	15	40	-	3	58	4.6
Québec	-	69	-	-	-	2	-	-	2	0.2
Ontario	12 461	106	12	633	338	4	*	425	767	60.5
Manitoba	182	16	*		3	1	*	-	4	0.3
Saskatchewan	5 907	10	195		83	1	7	-	91	7.2
Alberta	13 158	6	861		234	*	34	-	268	21.1
British Columbia	-	30	27		-	1	1	-	2	0.2
Yukon	-	23	-		-	1	-	-	1	0.1
NWT	-	59	-		-	2	-		2	0.2
CANADA	33 557	2 134	1 095	637	708	87	42	428	1265	100.0

(1) Total may not correspond to the sum of the elements due to rounding

* Too small to be expressed.

Source: Statistics Canada, Publication 57-202

Provinces west of Quebec use Canadian oil, primarily light oil used in gas turbines or diesel plants. In the Territories, Canadian diesel oil is used. All the oil used by the Atlantic region and Quebec is imported from outside Canada. In the Atlantic region, primarily residual oil is used for electricity production.

In 1982 Ontario imported almost 80% of its coal from the United States; the remainder came from Western Canada. The coal used by Manitoba was imported from Saskatchewan. Alberta, Nova Scotia and New Brunswick used their own coal. Saskatchewan relies primarily on its own coal, but imports additional amounts from Alberta.

The energy sources of electricity generation are changing significantly. Oil and gas use is decreasing while coal and uranium use is increasing. Hydro as a source remains steady. These changes reflect oil and gas price increases in the past ten years.

Nova Scotia and New Brunswick have used oil extensively for electricity generation but new coal-fired and nuclear plants will increasingly displace oil. In 1984, the last of four remaining coal-fired units at Nova Scotia Power's Lingan Plant will be put in service. New Brunswick will double hydro electricity imports from Quebec by 1985. Hydro electricity is expected to displace most of the oil-fired generation in Newfoundland, and Ontario has already displaced all of its major oil-fired generation. Alberta is the main user of natural gas for electricity generation but it is being displaced by coal-fired generation.

FORECAST ELECTRICITY DEMAND, PRODUCTION AND CAPACITY

This section forecasts electricity demand, sources of production, and installed generating capacity for Canada. Additional quantitative information can be found in Tables A6 and A7.

Forecast Demand

Figure 5 shows the close historical relationship between per capita economic performance, as measured by Gross National Product (GNP), and per capita electricity demand. Since per capita economic growth and population growth over the next twenty years is forecast to be significantly lower than that of the previous twenty year period, electricity growth will also be lower.

Table 13 shows growth in the period 1960-1983 of real GNP (i.e. GNP net of inflation), population, primary energy demand (i.e. the total energy available from the energy sources in their original state) and electrical energy demand, as well as the forecasts for each of these items for the period 1984-2000.

The table indicates an increasing role for electrical energy in Canada. The percentage of primary energy supplied in the form of electricity is expected to increase from 42% in 1983 to about 43% in 1990 and 46% in 2000.

Recent government initiatives are expected to increase electricity demand. The National Energy Program introduced by the Federal Government in October 1980 included financial incentives to convert from oil to non-oil sources of energy, including electricity. To the end of 1983 about 30% of the conversions under this program were to electricity.

This program has been strengthened by provincial government initiatives. Several utilities have implemented electricity marketing programs, primarily to sell the existing surplus capacity rather than to create a demand for new capacity that will require additional plant construction. The marketing programs will enable the utilities to keep rate increases at a level equal to or below the rate of inflation over the next several years. The utility marketing program is outlined in more detail in the section Developments in 1983.

Table 13. Historical and Forecast Annual Growth Rates-Real GNP, Population, Primary and Electric Energy.

	1960-1983 %	1973-1983	1983-2000
Real GNP	4.1	2.2	3.1
Population	1.5	1.2	0.7
Primary Energy	3.6	1.1	3.3
Electric Energy	5.3	3.7	4.2

Source: Energy Mines & Resources.

Forecasting electricity demand became a more difficult task in the last half of the 1970's,as a result of the economic dislocations caused by rapidly rising energy prices. The effects were felt on a global scale and adjustments were made in the amounts, types and uses of energy. The international price decreases in fossil-fuels in the past couple of years have added to the uncertainty. Adjustments in energy patterns continue to make economic forecasting difficult. Since electricity demand is so highly correlated with economic growth, the economic uncertainty leads to uncertainty about future electricity demand.

Despite the difficulties of forecasting, the long (5-10 years) lead times required to bring new generation facilities into service requires forecasts of future demand. Utility forecasts as of January 1984 are provided below in the form of average annual percentages for the probable rate of electricity demand growth. The extent of the changed perception of future demand is illustrated by the forecasts provided by the utilities last year, shown in brackets in Table 14.

Table 14: Utility Forecasts.

	1983 - 1990		1990 - 2000 %		1983 - 2000	
Nfld	4.0	(5.0)	4.3	(4.1)	4.2	(4.5)
PEI	1.0	(1.9)	1.0	(2.0)	1.0	(1.9)
NS	3.8	(3.3)	3.7	(3.9)	3.7	(3.6)
NB	3.4	(3.0)	2.2	(2.2)	2.7	(2.5)
Que	3.0	(3.6)	2.9	(2.9)	2.7	(3.2)
Ont	2.8	(2.3)	2.2	(1.9)	2.5	(2.1)
Man	2.4	(4.1)	2.8	(2.6)	2.6	(3.3)
Sask	2.2	(3.9)	2.5	(2.6)	2.4	(3.2)
Alta	5.3	(7.1)	4.1	(5.1)	4.6	(6.0)
BC	3.6	(3.4)	2.5	(3.1)	2.9	(3.3)
Yukon NWT	4.8	(3.3)	1.5	(3.3)	2.7	(3.3)
Canada	3.2	(3.5)	2.6	(2.9)	2.9	(3.2)

Source: Energy Mines and Resources - Utility Questionnaire.

Most major utilities reduced their forecast demand growth over the period 1983-2000. The changed perception of future load growth was most significant in Prince Edward Island, Quebec, Manitoba, Saskatchewan and Alberta. The significantly reduced electricity demand forecasts is not an indication that better forecasting techniques are required; it indicates the difficulty of making forecasts of electricity demand with a high degree of confidence in present highly uncertain circumstances. Rather than single value forecasts, it is appropriate to consider a range of demand forecasts with an assignment of statistical probability to each.

It follows that plant must be flexible enough to meet the demand as it develops, rather than built to satisfy a single forecast demand. Utilities are now taking an approach to planning which includes more flexible supply options and demand management options, i.e. rather than plan to build generation capacity to meet whichever demand develops, they are taking steps to alter peak demand requirements, by means of direct load management. The alternatives include some that might not be considered the most cost effective if there were a high degree of confidence in the demand forecast. They are, however, financially prudent and attractive in the present uncertain situation.

It appears that utility forecasts may have declined as much as they are going to in this cycle. Some utilities have already begun to increase their long range forecasts (Ontario Hydro has increased its forecast from 2.1% annual growth to 2.5%).

Figure 6 includes, for reference, the National Energy Board 1984 base case and alternative forecasts of electricity demand for Canada, the latest available NEB forecasts and the EMR forecast of July, 1983.

Included on the graph for comparison is the electricity demand forecast developed by the EMR Electrical Branch, based on forecasts provided by the major utilities. The NEB base case forecast is about mid-way between the EMR forecast and the utility-based forecast after 1990; the forecasts are all very similar to 1990.

Table 15(a) Forecasts of Generating Capacity by Fuel Type, Canada

	Conventional Thermal (GW)								Percentage of Total Capacity: Conventional Thermal						
	Oil	Gas	Coal	Total	Nuclear	Hydro	Other	Total	Oil	Gas	Coal	Total	Nuclear	Hydro	Total
1984	7.4	4.1	17.7	29.2	7.8	52.7	.5	90.2	8	4	20	32	9	59	100
1985	7.6	4.1	17.7	29.4	8.8	55.6	.5	94.3	8	4	20	32	9	59	100
1990	7.3	4.1	17.9	29.3	13.5	56.9	.6	100.3	7	4	18	29	14	57	100
1995	7.2	4.8	20.0	32.0	15.3	62.3	.7	110.3	6	4	18	28	14	58	100
2000	7.8	4.6	22.4	34.8	15.2	72.8	.7	123.5	6	4	18	28	12	60	100

Table 15(b) Forecasts of Production by Source Canada[1]

	Conventional Thermal (TWh)								Percentage of Production[2]: Conventional Thermal						
	Oil	Gas	Coal	Total	Nuclear	Hydro	Other	Total	Oil	Gas	Coal	Total	Nuclear	Hydro	Total
1984	6	5	64	75	45	253	2	375	2	1	17	20	12	67	100
1985	6	5	57	68	59	260	2	389	2	1	14	17	15	68	100
1990	7	7	55	69	93	284	3	449	1	1	12	15	21	64	100
1995	4	7	64	75	107	323	3	508	1	1	13	15	21	64	100
2000	4	7	92	103	105	371	4	583	1	1	16	18	18	64	100

1 To satisfy electricity demand in Canada. Does not include exports to the United States.

2 Totals may not correspond with the sum of the element due to rounding.

Source: Dept. of Energy Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

Forecast Production and Capacity

The forecast for future sources of generation capacity and production are shown in Table 15A, 15B. This indicates that oil-fired and gas-fired electricity production will continue to decline relative to the total over the period, but will increase slightly in absolute terms. Oil and gas will be used as the source of about 2.2% of total generation in 2000 compared to 3.6% in 1983.

Coal, uranium and hydro will be the major sources of electricity generation and are expected to displace much of the present oil-fired generation in the Atlantic Region. Most of the remaining oil generation will take place in Ontario and Quebec, for peaking purposes, and in some remote communities.

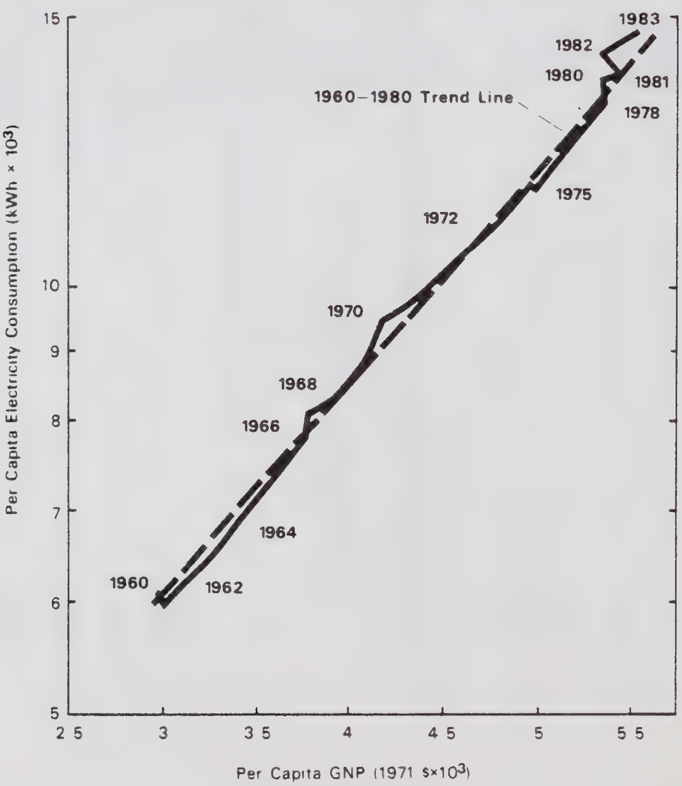
Table A6 shows that between 1983 and 2000 an additional 32,300 MW of capacity is anticipated. About two-thirds of this total will be in hydro additions. Increased nuclear capacity is expected to account for about one quarter of the total additions and coal for almost all of the remainder. Installed nuclear capacity will more than double from 1983 to 2000. Gas-fired and oil-fired capacity will remain at about their present levels.

It is likely that the data on the forecast mix of future generation will be reliable. However, the actual capacity additions for a given future year may require upward or downward adjustment to match future electricity demand.

Figure 5.

Figure 5

Historical Relationship Between Per Capita Electricity Demand And Per Capita Real Gross National Product



THE ELECTRICITY SUPPLY INDUSTRY IN CANADA

Electrical energy is supplied by three sources in Canada: investor-owned and public utilities are the primary sources, with a small number of industrially owned generation facilities. The industrial establishments generate energy mainly for their own use but a few sell energy to municipal distribution systems or utilities. Public and investor-owned utilities supply about 90% of Canada's electricity, with some provincial variations, as shown in Table A4. The percentage of energy produced by industrial establishments has decreased as shown in Table 16.

Industrial establishments with electricity generation supply on average 80% of their own total requirements. About 54 per cent of these plants are in the forest products industry, 15% in mining and 11% in metal processing. Quebec, Ontario and British Columbia have approximately 80% of the industrial establishments with generation facilities. This reflects the concentration of forest product, mining and aluminum smelting companies in these provinces. Nearly 90% of the electricity generated by industrial establishments is from hydro-sources.

Greater public ownership of electric utilities has been the trend in Canada, as provincial governments have taken over most investor-owned electric utilities. Consolidation of the supply industry contributes to efficiency and the provincial guarantee of debt lowers the costs of financing. This results in lower electricity supply costs. The provinces also acquire more direct control over electricity supply and pricing policy, considered to be important instruments in socio-economic planning. The major electric utilities in each province and territory are publicly owned except in Prince Edward Island and Alberta. An investor-owned utility distributes most of the electricity in Newfoundland.

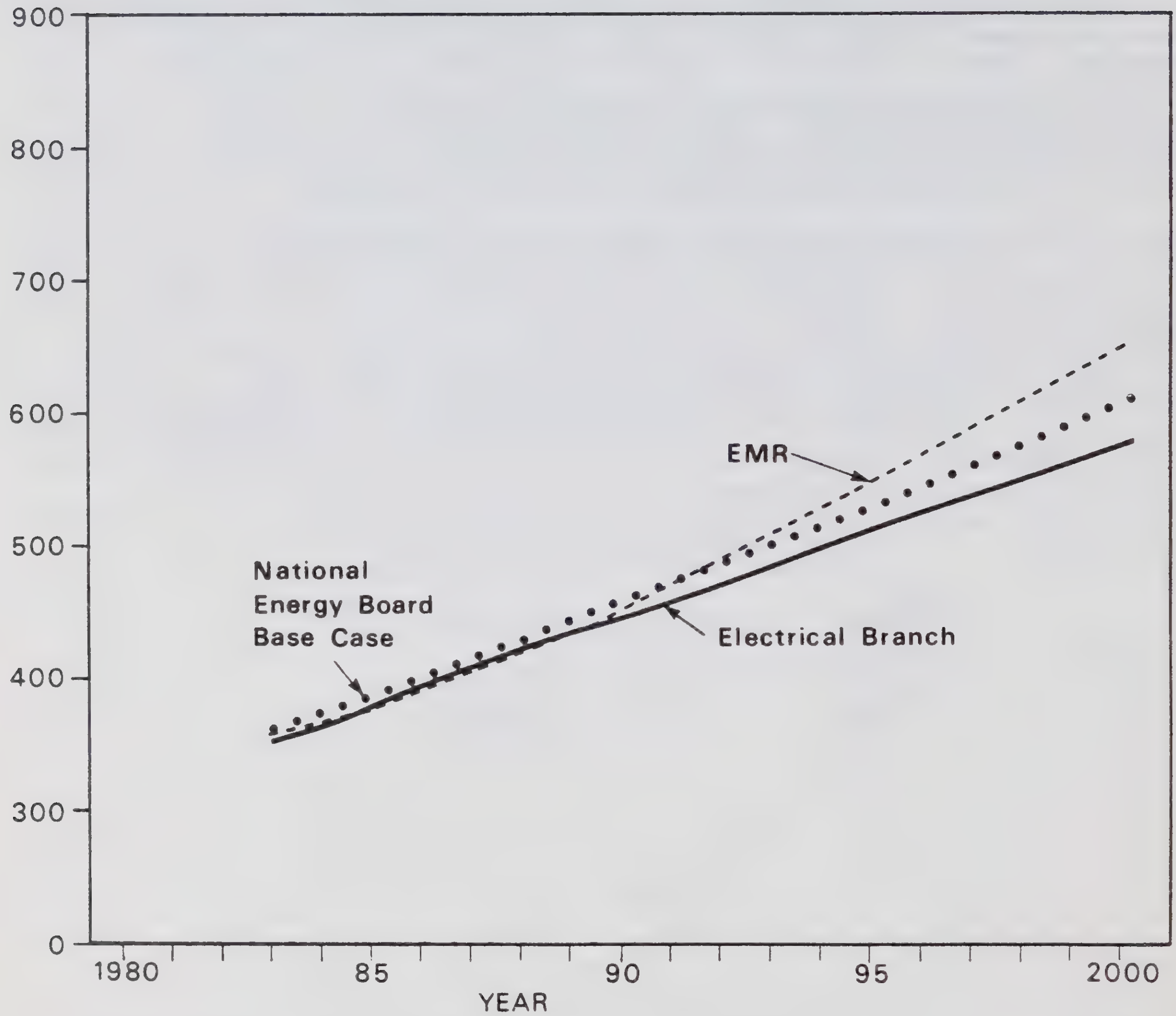
TABLE 16. ENERGY PRODUCTION BY UTILITIES AND INDUSTRIAL ESTABLISHMENTS, 1970-1982

Year	Utilities	Industrial Establishments
	(%)	
1970	84	16
1975	87	13
1977	88	12
1979	90	10
1981	90	10
1982	90	10
1983	90	10

Source: Statistics Canada, Publications 57-202, 57-001.

Figure 6

Electric Energy Forecasts



- ELECTRICAL BRANCH FORECAST BASED ON UTILITY FORECASTS OF DOMESTIC DEMAND.
- EMR FORECAST FROM INTERFUEL SUBSTITUTION DEMAND MODEL, DECEMBER,1983.

Table 17. Electric Utility Assets, Debt, Revenue and Employees, 1982.

	$ millions			
	Assets	Debt	Revenues	Employees
Nfld	2,379	1,579	415	2,346
PEI	85	33	59	196
NS	1,242	1,133	409	2,568
NB	2,774	2,274	584	2,663
Que	23,282	16,894	3,415	21,661
Ont	23,040	16,737	3,387	32,654
Man	2,981	2,705	475	3,850
Sask	1,617	1,260	366	3,510
Alta	4,594	1,810	1,258	5,884
BC	8,575	6,812	1,247	8,212
Yukon NWT	255	227	109	331
Canada	70,824	51,465	11,724	83,875

Source: Statistics Canada Publication 57-202.

In Alberta the Electric Utility Planning Council (EUPC) is responsible for co-ordinating generation and transmission facilities for all utilities in the province. The EUPC is a central planning body consisting of representatives from the utilities.

Two investor-owned utilities supply approximately 80% of the provincial supply in Alberta; municipally-owned utilities supply most of the remainder. The Alberta Electricity Marketing Board will help to achieve uniformity in rates for consumers served by the different utilities. The Board, which began operating in September 1982, reduces price differences by averaging generation and transmission costs. Price differentials due to distribution cost differences will remain. The regulation of utility earnings remains the responsibility of Alberta's Public Utility Board.

One investor-owned utility distributes 86% of the electricity used in Newfoundland, including about 90% of electricity used for residential purposes. It purchases about 85% of this electricity from the publicly-owned Newfoundland Hydro.

In the Yukon and Northwest Territories, the federally-owned Northern Canada Power Commission generates and distributes most of the electricity supplied. Two investor-owned utilities supply most of the remainder.

In all provinces but one, most of the electricity is distributed to consumers by the major utilities. The exception is Ontario, where a large proportion is purchased from Ontario Hydro and distributed by some 320 municipal utilities. Statistics Canada publishes the names of the electric utilities in each province in publication 57-204, Electric Power Statistics Vol. I.

The electricity supply industry is an important employer in Canada. As indicated in Table 17, 83,875, people were employed by the industry in 1982; 92% were employed by public utilities, and the remaining eight per cent by investor-owned utilities. The utilities had assets totalling $71 billion in 1982, and revenues of $14 billion.

Hydro-Quebec, Ontario Hydro and B.C. Hydro are the three largest electric utilities in Canada, and rank first, second and fifth respectively in terms of assets among all Canadian companies. Hydro Quebec and Ontario Hydro ranked second and fifth respectively among North American utilities in gross revenue in 1982. Together these two utilities account for approximately 65% of assets and revenues for Canadian electric utilities.

Comparative data of Canadian utilities with those of the major industrialized countries of the world appear in Table 18.

Table 18. Comparative Data of Utilities in the World's Major Industrial Countries in 1981.

	USA	USSR	JAPAN	CANADA	F.R. GERMANY	U.K.	FRANCE	ITALY
Generating Capacity(GW)	635	254	136	77	74	65	67	39
Energy Production (TWh)	2,295	1,259	523	339	302	260	236	151
Production Per Capita (KWh)	10,291	4,953	4,957	15,598	5,980	4,975	4,898	3,176
Average Annual Electric Growth Rate %								
1971-1976	2.9	5.9	3.9	4.5	4.3	0.9	3.9	4.3
1976-1981	2.3	3.9	2.8	5.7	2.1	0.0	7.1	2.2

Source: Electric Power Industry in Japan 1983.

CAPITAL INVESTMENT

Utility investment in new facilities reached $8.3 billion in 1983, slightly less than the $8.4 billion of 1982. Approximately 62% was for generation, 17% for transmission, 11% for distribution and the remainder for other items.

Table 19 shows the capital intensive nature of electricity supply and its importance in the Canadian economy. The figure shows electric utility investment compared to energy supply capital investment, total capital investment and Canada's Gross National Product (GNP). Two five year periods are shown (1966-1975) in addition to figures for 1980, 1981, 1982, and 1983.

Table 20 shows the original costs of utility fixed assets in service broken down by generation, transmission and distribution.

In Canada as a whole, the costs remain evenly divided between generation and the sub-total of transmission, distribution and "other", including office and storage buildings.

This investment pattern varies from one region to another, depending on the type of generation mix employed. The capital investment per unit of capacity added is significantly higher for hydro and nuclear capacity than for conventional thermal capacity. Hydro and nuclear generation are characterized by high capital cost and low operating cost, relative to a conventional thermal plant. In addition, hydro facilities often require higher capital expenditures for transmission facilities because of the remote location of the generation plants.

Table 21 provides information on capital expenditures in current dollar terms for electrical system expansion by province for 1983, and estimates for 1984 to 1993. This shows decreasing capital expenditures until 1989, reflecting the completion of projects now underway, and the present excess generating capacity, i.e. there will be no need to commit to building new generation capacity for a few years. After 1987, capital expenditures increase at a slow rate.

The forecasts of capital expenditures show a major change from last year. The 1984-1993 total of $164 billion is approximately 40% lower, reflecting the lower load growth forecasts in several Provinces. (See the section on Forecast Electricity Demand, Capacity and Production). The historical data in Table 22 indicates capital expenditures have increased at an average annual rate of 13.9% since 1965. The average annual rate of inflation over this period was 7.2%, resulting in real growth of approximately 6.7%.

An increasing emphasis will be put on upgrading transmission and distribution systems over the next few years, with relatively less emphasis on generation facilities.

TABLE 19. ELECTRIC UTILITY CAPITAL INVESTMENT

	1966-70	1971-75	1980	1981	1982	1983
Investment in electric power ($ billions)	6.8	12.9	6.4	7.3	8.4r	8.3
As percentage of investment in:						
Total Energy	55	56	44	40	42	42
Total Economy	8	9	10	9	11	11
As percentage of GNP	1.9	2.0	2.2	2.2	2.5	2.1

Source: Statistics Canada Publications 61-205 and 11-003E.
R: Revised

TABLE 20. ORIGINAL COST OF UTILITY FIXED ASSETS IN SERVICE

	1975		1977		1979		1981		1982	
	($millions)	(%)	($millions)	(%)	($millions)	(%)	(millions)	(%)	(millions)	(%)
Generation	10 549	48	14 628	51	19 177	52	24 943	53	28 352	54
Transmission	4 802	22	5 804	20	7 421	20	9 632	20	10 828	20
Distribution	5 007	23	6 302	22	7 950	21	9 554	20	10 650	20
Other	1 712	7	1 968	7	2 601	7	3 145	7	3 031	6
Total	22 070	100	28 702	100	37 149	100	47 274	100	52 861	100

Source: Statistics Canada, Publication 57-202.

TABLE 21.

FORECAST OF CAPITAL EXPENDITURES[1] BY ELECTRIC UTILITIES

(Millions of Current Dollars)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Newfoundland	177	132	96	53	201	806	1 498	1 758	1 437	1 152	571
Prince Edward Island	0	7	9	9	7	5	6	7	8	9	10
Nova Scotia	155	79	90	97	107	150	262	322	311	349	359
New Brunswick	74	165	58	76	86	76	88	72	60	57	60
Quebec	2662	2 088	1 913	1 817	1 085	1 049	1 200	1 379	1 924	2 467	3 112
Ontario	3123	2 935	2 540	2 697	2 671	2 593	2 266	2 424	2 481	2 405	1 948
Manitoba	157	146	95	101	150	373	578	657	720	853	550
Saskatchewan	319	272	296	144	133	166	236	330	427	311	249
Alberta	861	747	816	837	683	750	686	672	679	737	799
British Columbia	997	907	575	292	295	362	416	515	522	721	1 111
Yukon, NWT	22	6	5	2	11	2	2	4	4	4	7
CANADA	8547	7 484	6 493	6 125	5 429	6 332	7 238	8 140	8 573	9 065	8 776

Source: Utility estimates
(1) Fiscal and calendar years combined

TABLE 22. HISTORICAL ELECTRIC UTILITY INVESTMENT

Year	Construction				Machinery and Equipment	Total
	Generation	Transmission and Distribution *	Other	Sub-Total		
	(millions of current dollars)					
1965	438	277	12	727	212	939
1966	493	281	13	787	356	1 413
1967	577	262	36	875	390	1 265
1968	533	301	54	889	443	1 332
1969	511	281	63	856	546	1 403
1970	581	449	28	1 057	554	1 610
1971	572	472	36	1 079	668	1 747
1972	636	449	50	1 135	619	1 754
1973	808	539	69	1 417	827	2 244
1974	1 049	598	53	1 700	1 054	2 753
1975	1 691	874	96	2 661	1 296	3 957
1976	1 803	821	30	2 654	1 574	4 229
1977	2 205	911	43	3 158	1 726	4 884
1978	2 339	1 199	233	3 761	2 175	5 936
1979	2 516	1 424	181	4 121	2 243	6 364
1980	2 470	1 433	95	3 998	2 111	6 109
1981	2 768	1 554	92	4 414	2 905	7 319
1982	3153	1818	320.	5 291	3 086 r	8 377 r
1983(a)	-	-	-	4 440	3 866	8 306
1984(b)	-	-	-	3 607	3 710	7 317

* Transmission and Distribution includes street lighting. Generation includes transformer stations, dams and reservoirs.
(a) Preliminary actual data, no breakdown available.
(b) Intentions, breakdown not availble

Note: The totals may not correspond with the sum of the elements due to rounding.

Source: Statistics Canada Publications 57-202, 61-205, and 61-206.
Canada Year Book 1968-79.

FINANCING

From 1960 to 1976 debt for utility expansion increased as a percentage of total capital employed. Table 23 shows a decline in the debt proportion since 1976 as most utilities tried to reduce financial risk and their exposure to high interest rates. In 1976, debt accounted for 88% of capitalization in provinces with predominantly publicly owned utilities. It was 51% in those provinces with predominantly investor owned utilities. By 1982, debt for publicly owned utilities decreased to 87% and 48% for investor-owned utilities.

TABLE 23. ELECTRIC UTILITY FINANCIAL STRUCTURE

Province	1976		1977		1978		1979		1980		1981		1982	
	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)
					(%)									
Newfoundland	79	21	76	24	76	24	76	24	74	26	71	29	73	27
Prince Edward Island	53	47	53	47	52	48	53	47	54	46	55	45	55	45
Nova Scotia	103	-3	102	-2	99	1	98	2	95	5	97	3	97	3
New Brunswick	92	8	92	8	93	7	93	7	91	9	91	9	90	10
Québec	76	24	76	24	76	24	75	25	75	25	75	25	75	25
Ontario	77	23	77	23	78	22	78	22	78	22	78	22	80	20
Manitoba	97	3	97	3	96	4	94	6	94	6	95	5	96	4
Saskatchewan	73	27	77	23	78	22	78	22	80	20	85	15	89	11
Alberta	49	51	47	53	44	56	45	55	42	58	42	58	49	51
British Columbia	94	6	95	5	94	6	86	14	85	15	85	15	85	15
Yukon and Northwest Territories	102	-2	99	1	98	2	98	2	98	2	99	1	98	2
CANADA	80	20	80	20	80	20	78	22	77	23	77	23	78	22

(a) Debt: Long-term + loans and notes payable.
(b) Equity: Total of reserves and total capital and surplus.

Source: Statistics Canada, Publication 57-202.

The higher degree of business risk for investor-owned utilities in Prince Edward Island and Alberta requires their debt to be a lower percentage of the total capitalization. The debt of the publicly owned utilities is guaranteed by the provinces in which the utilities are located.

Studies indicate that the debt of a publicly owned utility should not be substantially above 80% of the capital structure. Some utilities which have a debt portion higher than 80% may take the opportunity of relatively low capital requirements during the next few years, to strengthen their financial positions. The provincially-owned utilities in Newfoundland and British Columbia have policies in place to do this. Newfoundland Hydro is making progress toward this goal, but contrasting provincial government policies (e.g. large increases in water rentals) have prevented B.C. Hydro from moving toward its objective.

The federal government provides loans for the Northern Canada Power Commission, a federal Crown corporation. It supplies most of the electricity in the Yukon and Northwest Territories.

In 1982 utilities used internally generated funds (net income plus non-cash charges to income) for about 30% of capital expenditures. This is approximately the same as for the period between 1965-75. Internally generated funds should meet about 30-35% of capital requirements in the next five years.

COSTING AND PRICING

Costing

The unit cost of supplying additional electricity increased rapidly during the 1970's. However in recent years cost increases have moderated significantly, resulting in relatively small increases in the real cost of electricity. This is expected to be the case for the next several years.

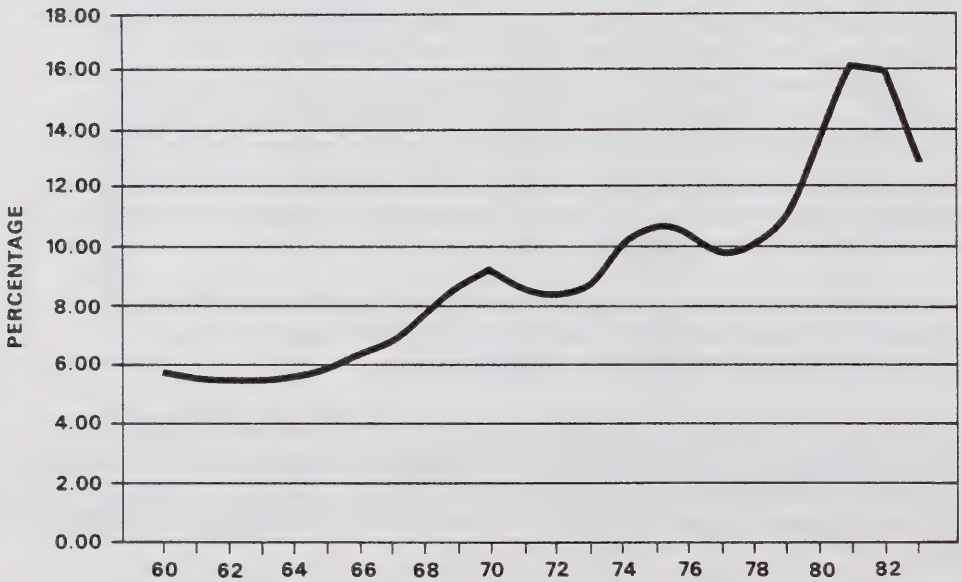
In the 1970's there were two basic reasons for rapid increases in the cost of electricity: the increase in the rate of inflation and the increase in the cost of fossil fuels. High levels of inflation affect the electric utility industry in two ways: it increases the capital cost of constructing additional facilities and it increases the cost of funds, an important consideration for a capital intensive industry.

The average interest on new long-term utility debt is shown in Figure 7 for the period 1966 to 1983. The index of electric utility construction costs is shown in Figure 8. This figure shows the significant increase in utility construction costs between 1973 and the present, a trend shared by most capital projects. Construction costs parallel the Consumer Price Index (CPI) prior to 1973 and from 1976 to the present. However, they increased rapidly during the period 1973 to 1977 relative to the rate of inflation, as measured by the CPI.

Figure 9 indicates the increases in fossil fuel costs experienced since 1973. For Canada in total, the fuel cost per kWh generated from fossil fuels increased five-fold between 1973 and 1980, but oil costs have moderated since 1980. The impact of the cost increase varies between regions of the country depending on the type of fuel used, its source and the percentage of total energy supply derived from fossil fuel plants. Earlier sections of this publication provide regional breakdowns for fuel use and generation mix.

FIGURE 7

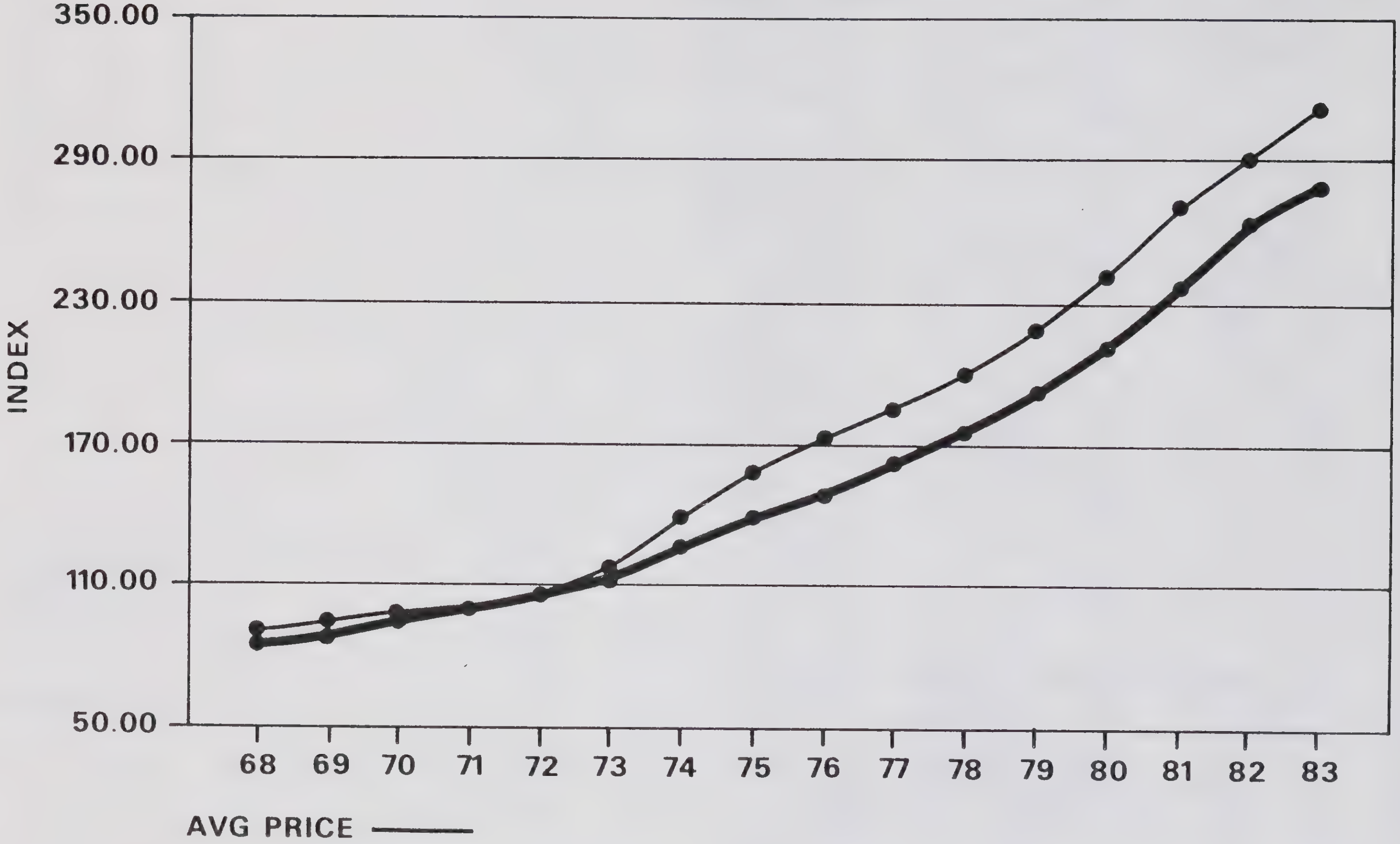
AVERAGE INTEREST ON PUBLIC UTILITY NEW LONG-TERM DEBT, 1960-1983



SOURCE: McLEOD, YOUNG, WEIR UTILITIES BOND YIELDS

FIGURE 8

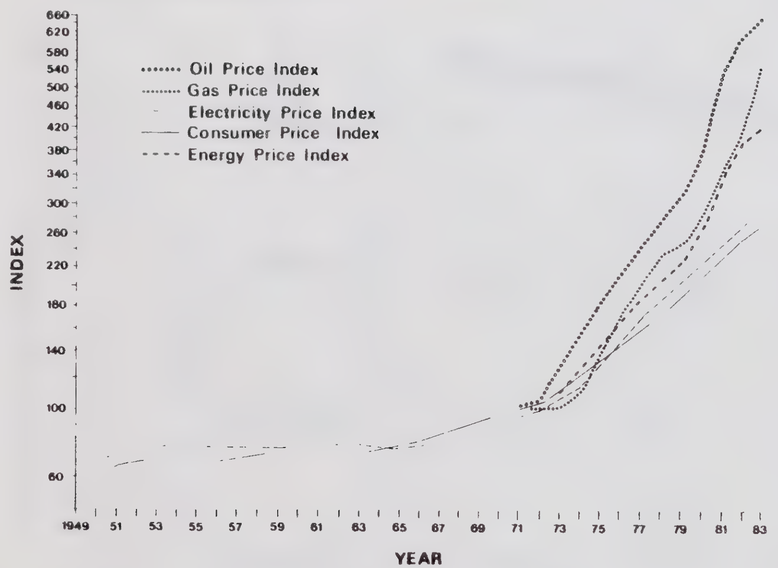
PRICE INDEX TRENDS IN UTILITY CONSTRUCTION 1965-1983



SOURCE: STATISTICS CANADA PUBLICATION 62-007

Figure 9

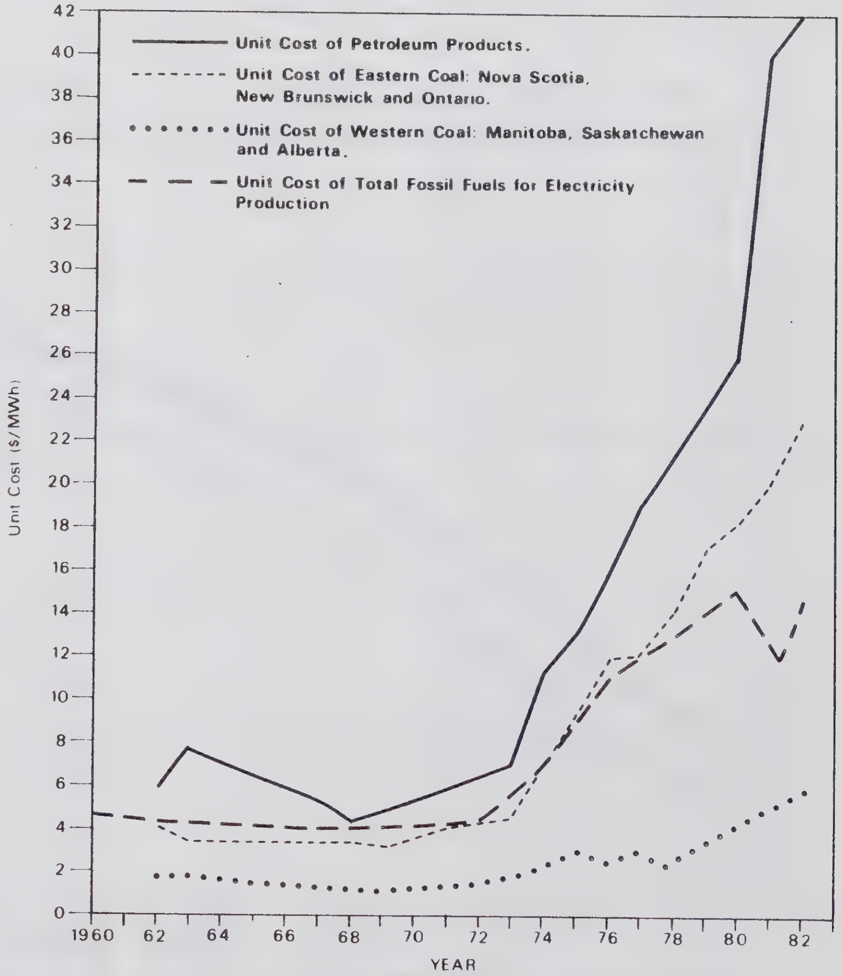
Price Indices, 1949–1983



SOURCE: Statistics Canada Publication 62-010

Figure 10

Unit Cost of Fossil Fuel for Electricity Production 1960-1982



Source Statistics Canada Publication 57 202

Pricing

Figures showing average revenue from electricity sales for each province are provided in Table 24. The unit revenue for Canada was stable up to 1972, when the cost escalated for reasons outlined in the section on Costing.

These costs increased more rapidly in some regions than others, depending on differences in generation mix, fuels used, and rates of system expansion to meet increased demands for electricity. Table 25 gives monthly electricity costs for selected Canadian cities. Table 26 details the average annual rate increases for customers in each province since 1974.

Figure 10 illustrates the movements of the electricity and oil/gas components of the Consumer Price Index, and the movement of the Energy Price Index as well as the Consumer Price Index itself. It indicates that the electricity price component increased more slowly than, or equal to, the rate of increase of the CPI for most of the period since 1955. The exception is the period from 1974 to 1977, when the electricity price component has increased significantly more slowly than the oil and gas price indices.

There are some innovative changes taking place in electricity pricing in Canada, such as time-differentiated pricing. Several utilities indicate they are moving away from the declining block structure, toward a rate structure of a fixed service charge plus a single rate for energy. Utilities are also lessening the complexity of rate structures by reducing the number of rates.

TABLE 24. AVERAGE REVENUE FROM ELECTRICITY SALES BY PROVINCE

Province	1971	1972	1974	1975	1976	1977	1978	1979	1980	1981	1982
				(CURRENT CENTS /kWh)							
Newfoundland	1.1	1.1	1.3	1.4	1.4	1.7	2.0	2.2	2.3	2.8	3.6
Prince Edward Island	3.0	3.0	3.7	4.1	5.1	5.9	6.4	7.2	8.1	10.0	12.0
Nova Scotia	1.8	1.8	2.0	2.5	2.8	3.9	4.4	4.6	4.5	4.9	5.9
New Brunswick	1.5	1.5	1.6	1.9	2.0	2.4	3.2	3.7	4.1	4.8	5.1
Québec	1.0	1.0	1.1	1.3	1.4	1.5	1.7	2.0	2.2	2.6	3.1
Ontario	1.1	1.2	1.4	1.6	1.8	2.3	2.4	2.6	2.9	3.2	3.6
Manitoba	1.0	1.0	1.2	1.4	1.7	1.9	2.3	2.7	2.8	2.8	2.9
Saskatchewan	1.7	1.6	1.6	1.8	2.1	2.4	2.7	2.7	2.9	3.6	4.0
Alberta	1.5	1.5	1.7	2.0	2.4	2.7	3.1	3.2	3.4	4.1	4.9
British Columbia	1.3	1.3	1.4	1.6	1.8	2.1	2.2	2.4	2.6	3.0	3.8
Yukon	2.4	2.4	2.6	2.7	3.5	4.1	4.4	4.9	5.3	6.7	8.3
Northwest Territories	2.5	3.2	3.6	4.0	5.2	6.9	7.7	9.0	10.0	11.5	14.8
CANADA	1.2	1.2	1.3	1.5	1.7	2.0	2.3	2.5	2.8	3.1	3.7

Source: Statistics Canada, Publication 57-202.

Table 25. Monthly Electricity Costs for Selected Canadian Cities, January 1983

Sector	Residential	Commercial	Industrial
Billing demand (KW)	-	100	1000
Consumption (KWh)	1000	25 000	400 000
		$	
Vancouver	57.27	1521.40	17 847.96
Calgary	44.88	1383.28	15 361.18
Edmonton	42.60	1224.80	16 443.60
Regina	36.00	1203.15	14 661.50
Winnipeg	36.86	815.31	9 257.30
Toronto	39.83	1252.80	14 985.00
Ottawa	36.70	949.90	13 557.40
Montreal	37.07	1261.00	15 169.50
Moncton	52.79	1719.40	16 970.00
Halifax	57.41	1784.83	18 584.98
Charlottetown	113.38	3114.31	42 619.66
St. John's	57.27	1521.40	17 847.96
Whitehorse	59.52	1915.50	N/A
Yellowknife	93.00	2785.00	54 760.00

N/A: not applicable

Source: Statistics Canada, Publication 57-203

TABLE 26. AVERAGE ANNUAL RATE INCREASES, 1974-1983.

UTILITY	RATE CHANGES (%): AVERAGE OF ALL CUSTOMER CLASSES								
	1975	1976	1977	1978	1979	1980	1981	1982	1983
B.C. Hydro	6.2	14.2	12.1	13.4	5.5	7.6	2.6	20.0*	6.0
Alberta Power	21.3	11.4	20.2	-	-	12.3	28.9	-11.6*	-
Trans Alta. Utilities	17.6	25.8	14.7	15.6	7.5	-	13.0	4.0	15.0
Edmonton Power	13.6	10.1	6.0	8.1	-	26.0	12.0	13.2	8.0
Saskatchewan Power	27.0	13.0	17.0	3.3	8.3	7.9	16.1	-	12.6
Manitoba Hydro	17.4	16.6	15.0	14.9	14.4	-(1)	-	-	9.5
Ontario Hydro	11.4	14.9	25.6	5.7	7.7	7.3	10.0	10.0	8.2
Hydro-Québec	9.8	10.3	9.9	18.7	13.7	13.3	10.6	16.3	7.3
N.B. Power	10.0	12.0	16.6	9.9	7.9	7.8	9.8	-	8.8
N.S. Power	4.6	-	43.0	14.0	12.5	-(2)	-	-	36.6
Maritime Electric	20.0	(8.0)	17.0	13.0	-	13.1	21.4	-**	-
Nfld. Light & Power	33.5	13.4	9.8	21.2	12.4	11.8	14.6	-	12.0
Nfld. Hydro	-	14.0	8.4	25.0	-	19.0	15.8	-	18.2

NOTES

(1) The provincial government froze the rates in 1979 until 1984.

(2) The provincial government froze the rates in 1980.

(3) Information available only from 1976.

* Based on residential category.

** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges

Source: Energy Mines and Resources.

ALTERNATE ENERGY SOURCES

This section provides an update on the developments in Canada of alternative energy sources. These include geothermal energy, ocean energy, tidal energy, river current energy, wind energy, small scale hydro, photovoltaics, electro-chemistry, biomass and peat. Canada's favourable resources of conventional energy for electricity production from hydro, coal and nuclear sources will limit the scope for harnessing these less conventional supplies.

Geothermal Energy

Federal government geothermal energy research and development funding began in 1976. Originally, the objective of the program was to identify and assess exploitable geothermal resources in Canada. Since then four types of sources have been identified. These are:

1) Volcanic sources, located in the Cordillera of British Columbia and characterized by high temperature steam flows;

2) Non-volcanic sources in the mountains of Western Canada, characterized by lower temperatures than found in volcanic regions;

3) Sedimentary sources, located in the sedimentary basin of Alberta and Saskatchewan, characterized by uniform but relatively low temperatures over the area;

4) Atlantic sources, which are not uniform but represent an indigenous energy source.

Research is shifting towards extraction technology as knowledge of the resource increases. The work of delineation and development of exploration techniques will continue on all four sources.

The program has identified geothermal resources for potential electricity production at Meager Creek and at Mt. Cayley (volcanic sources) north of Vancouver B.C. and for space heating purposes (sedimentary source) at the University of Regina in Saskatchewan. Economic restraints and projected low demand have resulted in a slowdown of these site research activities.

The potential of the Meager Creek site is estimated to be in the range of 500-1,000 MW of electricity capacity. Following initial federal government drilling, B.C. Hydro continued the drilling program in 1982. Three production-sized wells have been completed, to depths exceeding 3,000 metres. Although temperatures up to 280°C have been observed, testing indicated fluid flow rates are not sufficient to justify construction of a demonstration generating plant.

At the University of Regina, geothermal energy as a supplementary energy source for the university's central steam generating plant is under consideration. A single production-size hole has been drilled. Although there is no fixed schedule as yet, the large diameter production hole is being studied for heat and fluid flows.

The geothermal potential of two locations, one in B.C. and one in the Yukon, as sources of power and heat supply to remote communities is being considered.

Ocean Energy

The oceans represent a vast source of renewable energy. Wave energy and salinity gradients hold potential benefits for Canada. Ocean energy sources such as ocean currents and thermal gradients are of international interest. Canadian and International Energy Agency (IEA) research and development programs are evaluating the potential of these resources.

An assessment has been made of ocean energy forms in a Canadian context. A prototype generator which extracts energy from salinity gradients by reverse electrodialysis has been developed by a British Columbia company.

A low level of activity will be maintained on wave energy and thermal gradient technologies so new developments can be assessed in terms of applicability to Canada. Extraction of energy from the ocean is a long range and site specific endeavour. It is an uncertain competitor with other energy sources in Canada.

Tidal Energy

The Nova Scotia low head hydro demonstration project, situated in the tidal portion of the Annapolis River in Nova Scotia, was placed in-service in May 1984. The project is expected to provide information on the operation of a single-stage tidal power project and on the cost-effectiveness of the new type of low-head turbine (Straflo) for river and tidal applications.

Current research and development activity consists of surveying Canadian potential for tidal energy developments and providing technical support for tidal applications.

EMR has contributed to an investigation by B.C. Hydro of tidal power generation potential for the Queen Charlotte Islands, through the Remote Community Demonstration Program.

The National Research Council is developing technology to physically and mathematically model tidal basins. This technology would predict barrage performance and environmental effects such as tidal amplitudes, currents, and sediment transport. Similar technical support by EMR will continue for the Fundy tidal power project.

Over the next three years surveys will be conducted on the tidal power potential of Ungava Bay. While evaluations of the tidal regime and suitable sites are incomplete, the fully harnessed potential of Ungava Bay could rival the James Bay hydroelectric development.

Energy from River Currents

Development of a vertical axis hydraulic turbine (VAHT) similar to a Darrieus windmill, has been ongoing since 1979 at the Hydraulics Laboratory of the National Research Council in Ottawa. Model tests have been carried out on a 0.8 metre diameter rotor with three, four or five vertical symmetrical hydrofoils.

Vertical axis hydraulic turbines combine windmill and hydrofoil technology. In the summer of 1982, a prototype ducted free-stream VAHT was moored in the St. Lawrence River at Cornwall, Ontario, and hooked to the St. Lawrence Power Company's grid. Efficiency of the rotor and duct combination was 34%, based on duct entrance area and river velocity measured a short distance upstream. The unit was removed in the fall after 1150 hours of operation. In the summer of 1983, the same VAHT was again installed at Cornwall, but with the duct removed. The unit ran for 1190 hours, and had an efficiency rate of 33%. In both ducted and open rotor tests, drive train and generator efficiencies were poor, 48% and 61% respectively, and delivered only 2.5 kW of electrical power to the grid on shore.

The field tests have shown that this technology is not yet cost-effective for producing small amounts of power unless a site with currents greater than 3 metres per second and depths over 3 metres is available. As few rivers have these conditions occurring naturally, excavation or some structures may be required to achieve them locally. Tidal current areas are especially well suited to VAHTs, the main complication being the mooring arrangement which must allow for water level changes. The VAHT used at Cornwall will be modified to produce 20 kW of electricity and tested for tidal application in 1984. Two locations in the Bay of Fundy are being considered as possible test sites.

Wind Energy

National distributions of wind energy density have been mapped showing the greatest wind power potential. Studies in aerodynamics and structural dynamics of rotors are continuing with attention being directed toward drive-train controls and systems engineering aspects of wind energy conversion systems (WECS). Four grid-coupled systems (usually 50 kW) and a stand alone wind/diesel hybrid system are being tested in conjunction with provincial utilities and agencies.

A prototype 500 kW system was installed at the Atlantic Wind Test Site in Prince Edward Island during the fall of 1983, with funding from the National Research Council (NRC). It is currently the largest wind turbine in Canada.

NRC and Hydro Quebec are funding equally the cost of designing, building and evaluating a prototype 4 megawatt vertical axis wind turbine (VAWT). Called project EOLE, this machine will have two troposkein shaped blades encompassing a swept area of 4000 square meters, and will be located at La Fonderie, Quebec.

Small Scale Hydro

Most provinces and both territories are assessing small scale hydro potential and developing demonstration projects. Emphasis is on potential replacement of diesel generation in remote communities.

Analysis indicates economic viability for expansion of existing small hydro stations or the retrofit of decommissioned hydro units within power grids. However, the greater capital cost of development of new small hydro sites will restrain their development due to the longer pay-back period.

Conservation and Renewable Energy Demonstration Agreements (CREDA), a cost-sharing program between demonstrators and the Federal and Provincial/Territories governments, have encouraged the adoption of some of the most cost-effective small scale hydro installations in the country and have sought to establish broadly the technical and economic feasibility of small hydro in real-life applications.

Under CREDA, $5 million worth of new or recommissioned facilities ranging from 200 watts to 2,500 kW were supported: four in British Columbia, one in the Yukon, seven in Ontario, two in New Brunswick and one in Newfoundland. In addition, three projects were supported in Nova Scotia through a similar agreement. The federal government contributed over $750,000 to these projects.

CREDA expired in March, 1984 with a one year wind-down. It was replaced by ENERDEMO-Canada, a new $80 million conservation and alternative energy demonstration program developed to fill a need for a truly national program, drawing together existing resources and ensuring uniform delivery everywhere in Canada.

Small-scale hydro development is also supported through the Remote Community Demonstration Program (RCDP). This program was implemented by the federal government in 1982 to meet the special energy problems of remote communities. More than 400 communities across Canada remain unconnected to an electrical grid or natural gas system. The two-phase, $16 million program combines the initiatives of the Remote Community and Arctic Community Demonstration Programs. These were originally announced in the National Energy Program and will expire in 1989.

Phase I of the program, started in October 1982, provides financial assistance for a limited number of community based studies to investigate off-oil opportunities. Financial assistance for demonstration of technically and economically feasible energy supply and conservation options will be provided in Phase II.

While the program is not restricted to small-scale hydro development, several hydro projects are the subject of Phase I study proposals. Small-scale hydro technology is considered to be one of the most promising supply sources for many remote communities.

The federal government funded a consultant study for identification of environmentally compatible small-scale hydroelectric potential in New Brunswick and Prince Edward Island. The project screening and assessment techniques developed during the study have proven useful for studies conducted by utilities. An application manual for hydrologic design methadologies for small-scale hydro at unguaged sites has been completed.

Photovoltaics

Photovoltaics refers to the technology of direct conversion of sunlight to electricity. Canada has an established industrial base for this solid-state technology. Electricity generation by photovoltaic devices has been limited to low power needs (remote microwave repeater stations) or exotic installations (earth-satellite power supplies).

Photovoltaic technology is a renewable energy option and significant cost reductions have been achieved. Over the next 20 years photovoltaics will have more impact on remote communities than on generation in Canada as a whole. Research and development is aimed at reducing costs. Studies are being carried out on (I) thin film devices based on silicon, gallium arsenide, copper/indium/selenium mixtures and other semi-conductor compounds, (II) improvements to silicon technology, (III) remote stand-alone sytems and (IV) utility connected systems.

Biomass

Biomass is an abundant natural resource in Canada and it supports an important resource processing industry. The forest industy produces large amounts of waste which has been used historically to produce low cost heat and electric energy.

The Bioenergy Development Program, administered by Energy Mines and Resources is a research and development program dealing with the conversion processes of biomass into all forms of energy including the production of solid and liquid fuels.

Electricity can be produced from biomass in either of two generic ways. First, through direct combustion and steam generation to power conventional steam turbines, and second, through a gasification process in which the intermediate product (ususally low BTU gas) is used to fire a diesel or turbine generator. The technology for direct combustion and steam generation is well developed and in reasonably widespread use where applicable, while biomass gasification technology has been the subject of R&D effort and a few demonstration projects under Conservation and Renewable Energy Demonstration agreements with the provinces and territories.

The primary new market for biomass generated electricity is remote communities and other locations with ready access to adequate biomass resources. Most of the demonstration projects have focussed on remote community applications, and electricity from biomass is a serious supply option under investigation in Phase I of the Remote Community Demonstration Program. In addition, the federal government has provided funding assistance for several cogeneration projects with biomass under the Forest Industry Renewable Energy Program.

Peat

Canadian peat resources are believed to be the second largest in the world and contain potential energy second only to coal among Canada's fossil fuels. Although such energy resources are currently being exploited in Ireland, the USSR, and Finland, they remain virtually untapped in Canada mainly due to technical, economic and environmental constraints: our resources have not been adequately defined on a national basis; our climate places seasonal restrictions on production; and current technology raises serious environmental and ecological concerns.

Activities of NRC's Peat Program include a peatland inventory that will determine peatland area, volume of various peat types, and by 1985, a first level estimate of Canada's peat deposits. In conjuction with field studies carried out in the Newfoundland and Labrador region, the Prairie region, the St. Lawrence Lowlands and the Pacific coast region, a computerized Wetlands Registry is being developed to store and evaluate peatland data generated by current and future inventory projects. Other activities include research into various slurry mining methods and the assesment of mining equipment. Significant research is being directed to the problem of peat dewatering and small-to-medium wet mining of peat slurries in order to establish a more or less year round peat energy industry.

Under CREDA, the first Canadian demonstrations of peat harvesting, transportation and combustion on an industrial scale have been carried out at Grand Falls, Newfoundland, and at small sod peat operations in southern Newfoundland and northern Saskatchewan.

RESEARCH AND DEVELOPMENT

Structure of Research and Development in Canada

Electrical research in Canada is carried out by governments, industry, associations, consultants and academic institutions. Research and development encompasses electricity in a broad range of engineering disciplines, social and economic topics and environmental questions. They contribute to the production, distribution and use of this energy form.

At the federal level, the Department of Energy, Mines and Resources (EMR), the National Research Council (NRC), the Natural Sciences and Engineering Research Council (NSERC) and Atomic Energy of Canada Limited (AECL) have administrative and, in the cases of NRC and AECL, functional responsibility for electrical research.

Co-ordination of federal energy R&D is provided by the Interdepartmental Panel on Energy R&D. It makes recommendations to Ministers on present and future energy R&D programs. The Panel's mandate includes monitoring federal energy R&D activities in the context of the whole national effort and international activities. EMR provides the chairman and secretariat to the Panel.

EMR also provides grants to the Canadian Electrical Association (CEA) and to academic institutions under the Research Agreement Program. The NRC contracts to industry, and does in-house research

NSERC provides funding to academic institutions under regular operating grants, strategic grants and PRAI (project research applicable in industry) grants.

Four of the public utilities (Ontario Hydro, Hydro Québec, Saskatchewan Power and B.C. Hydro) maintain in-house research programs which undertake a variety of activities linked with design and operating characteristics of the electric utility business. Manitoba Hydro participates in research activities of the Manitoba HVDC Research Centre, and contributes to the funding of this organization.

The Canadian Electrical Association's research program is funded jointly by the Canadian government and the utilities. The program is managed by representatives from industry and government who identify research topics and manage the performance of studies selected through a committee structure. The studies are contracted out to industry, academic institutions, consultants and utilities with research facilities. The participation of utility personnel helps to minimize duplicating studies or neglecting certain areas.

Apart from administering its research program, one of the important functions of the CEA is liaison with international research organizations to improve program selection for Canadian utilities.

During 1983/84, research expenditures related to electricity were $374 million. Of this, $229 million was spent by Atomic Energy of Canada Limited (AECL) on the nuclear power program. Over $118 million was spent by the four electric utilities with research facilities. The co-operative program managed

by the CEA received funds of $12.5 million. Finally $14.9 million was spent on federal research and development expenditures relating to electrical energy and to the fuels associated with its production (excluding AECL's program expenditures).

Overview of Research Programs

Federal Government

Nuclear

Research for nuclear power development by Atomic Energy of Canada Limited (AECL) includes maintenance of reliability and safety standards set by Canadian CANDU reactors. AECL operates laboratories in Chalk River, Ontario and Pinawa, Manitoba. Its research mandate is to develop and apply nuclear technology for peaceful purposes to benefit all Canadians. In 1983/84 its resources amounted to $229 million, compared to $235 million (1983 dollars) in 1982/83 (approximately 80 per cent from Parliamentary appropriations and 20 per cent from commercially generated revenue in each year).

Technical programs continue in power reactor systems, heavy water processes, environmental protection and radioactive waste management, advanced fuel cycles, advanced systems research and new applications for nuclear technology.

The CANDU reactor's safety was further demonstrated in 1983. In August 1983, when a pressure tube at Ontario Hydro's Pickering unit 2 ruptured unexpectedly with no prior leakage or other indication of an impending problem, the reactor was shut down by normal procedures, without the use of either fast shut down or emergency cooling systems, and without any adverse health consequences. Safety studies continue in the laboratory and construction of a 7-megawatt thermalhydraulic test facility to verify predictions of primary coolant behaviour under potential accident conditions is nearly complete. (For further details see Pressure Tube Problems in section titled Developments in 1983).

Although used nuclear fuel is now safely and economically stored in the operating plants, it will eventually be desirable to dispose of the fuel or the wastes arising from its recycling. Progress has be made in the research program investigating the concept of disposing of these wastes in stable crystalline rock formations in the Canadian Shield. Systems variability analysis, a technique developed to assess the consequences of release from a nuclear waste vault, is attracting increasing attention in other countries for application to other wastes. A major facility for testing the resistance to leaching of used fuel is complete and experiments have begun. Surface facilities of an underground research laboratory to study processes and properties involved in geological disposal have been completed and underground construction is underway.

To assure Canadians of a long-term supply of energy from nuclear sources, experiments continue on the recycling of used fuel. Emphasis is being placed on studies which may allow the costs of fuel recycling to be decreased as well as tandem fuel cycle studies to determine if used fuel from light water reactors can economically be recycled in CANDU reactors. Other studies are determining the conditions under which various advanced fuel cycles will be economically competitive.

Processes originally developed for the production of heavy water are being adapted to remove tritium from the heavy water of CANDU reactors. Tritium could become a useful fuel for fusion reactors.

Research programs in physics, chemistry, material science and health sciences provide the base for understanding the phenomena involved in the applied R & D programs. The physics program is being enhanced by the addition of a superconducting cyclotron to the Tandem Van der Graaf accelerator. Increased effort is being placed on new and spinoff applications. These vary from use of a safe low-power reactor for heating remote communities to use of accelerators to sterilize industrial wastes.

Electrical energy is particularly influenced by the non-nuclear areas of the federal energy research program. The objectives stem from the 1980 National Energy Program and include Research and Development for substitution, alternate energy sources and efficient energy utilization. Emphasis has been placed on environmentally acceptable and energy efficient coal utilization technologies.

Coal

Heavy dependence by the Atlantic Provinces on imported oil for power generation prompted increased federal emphasis on the use of indigenous coals as a substitute. Accordingly, the National Energy Program provided up to $150 million over five years to develop and demonstrate promising coal utilization technologies that permit coal to be consumed in more efficient and environmentally benign ways.

A four part program, heavily oriented to technologies that could deal with high sulphur Atlantic coals, has been established as follows:

1) A small scale evaluation of coal-water mixtures as a direct substitute for residual oil. The mixtures offer the advantage of enabling removal of sulphur during the fine grinding of the coal, and require only modest alterations to existing oil-fired burner systems. Tests on a smallexisting utility boiler are underway at Chatham, N.B. for a total cost of $7.2 million. Further tests are planned for an oil-fired boiler at Charlottetown, PEI in 1984-85.

2) Testing of fluid bed combustion systems. This is a new technology which permits removal of sulphur during combustion through chemical combination with limestone. Because the fluid bed system is amenable to the use of low rank and waste coals as well as other solid fuels such as wood wastes, the technology will have application throughout Canada. Current activity includes an industrial size bubbling fluid bed at Summerside, PEI to which $9 million was contributed; an $8 million 10,000 hours boiler materials testing program in a bubbling fluid bed at Pt. Tupper, N.S.; and a $1 million program to evaluate new types of burners and to prepare conceptual designs for a new 20 MW circulating fluid bed demonstration project at Chatham, NB.

3) A $1 million flue-gas desulphurization activity in conjunction with the Canadian Electrical Association involves information and technology exchanges among utility engineers and work on improved burner designs for existing coal-fired units.

4) A program to assess the upgrading potential for Atlantic coals is being funded in the amount of $2 million.

Other Activities

Two alternative energy sources have received particular attention. $18.7 million in federal funds has been allocated to the construction of Tokamak, an experimental fusion device, at Varennes, Quebec. In addition, the EOLE wind demonstration project will receive $17.6 million in federal funds from NRC. It will be capable of generating 3.8 MW and will supply power directly into the Hydro-Quebec grid.

A federal sub-program aimed specifically at electric power research is continuing. Activities include research on dielectrics and electrical measurement technologies, and high voltage direct current (HVDC). HVDC research has been conducted by the NRC since 1960. In 1982, a contract was awarded to the Manitoba HVDC Centre.

The energy conservation program promotes the efficient use of energy and conservation of liquid fuels. Equipment for electricity load control helps flatten load patterns and results in more efficient use of generating capacity and fuel. Substitution options allow conversion to electricity where supply and price permit.

Electrical energy "storage" systems, industrial process heating, electric space heating thermal storage heat pumps, and rail electrification are some of the areas being investigated by several departments and agencies with funding through the Conservation Research and Development Program.

In conjunction with EMR, the Ministry of State for Science and Technology evaluated hybrid heating and its potential as an efficient user of electrical energy. Hybrid heating concepts include the addition of electricial resistance heaters or heat pumps to existing non-electrical heating units (e.g., oil or gas). Consumers could use the electrical systems during off-peak hours of electricity demand. During peak periods, non-electric heating sources would be used. The broad implementation of hybrid heating would reduce peak demand,thereby permitting more efficient use of generating capacity. It would also substantially reduce the need for fuel oil.

To complement the above work, research is being funded by EMR at Saint Mary's University in Halifax to develop low-cost thermal storage units based on commercial grade salts. At higher temperatures, thermal storage units may be an alternative to non-electric heating units for hybrid heating technology, providing a means for peak sharing and load control.

The Canada Centre for Mineral and Energy Technology (CANMET) is assessing the potential application of plasma arc technology in Canada which will aid in defining the needs for further R&D. This technology provides a high temperature heat source using electricity. Applications include smelting and pyrometallurgy and offer more flexibility than conventional arc technology. Successful development could lead to a major off-oil or gas alternative in instances where electricity availability and rates make the process feasible. Adoption of the technology by the steel industry could reduce the requirement for metallurgical coke. The technology is also capable of being used for eliminating toxic organic wastes.

To increase the options for efficient use of electricity, research is being conducted on both industrial and residential heat pumps. Progress has been made on the development of a residential heat pump for greater efficiency in the Canadian climate. Several industrial heat pumps have been installed and are being monitored to establish credibility for industrial applications.

The National Research Council and Transport Canada support some research on electric vehicles, particularly the development of advanced batteries. Conventional lead/acid batteries have insufficient power density but alternatives such as lithium/iron sulphide or sodium/sulphur have much better power densities, although they have their own drawbacks such as a limited number of recharges.

Commercial Utilities

Hydro-Québec

R & D expenditures by Hydro Quebec's Research Institute (IREQ) totalled $49.8 million in 1983. In keeping with Hydro Quebec's stated objective of making electricity a more commercially valid alternative in the Quebec energy market, the Research Institute formed a multi-disciplinary team in the field of industrial applications of electricity, and grouped energy-production and utilization activities in a single department.

In pursuit of its aim to promote the development and application of electrical technologies in Quebec industies, IREQ purchased plasma technology developed by Noranda, and also initiated projects with industrial partners to study and set up pilot plants that will use these technologies.

To increase the efficiency and reliability of Hydro Quebec's power system, considerable effort was expended on interconnections and in July 19, 1983, a synthetic test circuit for performing major tests on electrical equipment was commissioned. This test circuit supplies voltage and power levels of 2000 kV and 7000 MVA during out of phase interrupting tests on complete poles of 735 kV circuit breakers.

In 1983 work progressed on the EOLE *(wind generation) and Tokamak*(fusion experiment) projects. A 56 kw Darrieus wind turbine was erected at IREQ and the initial stages of the installation of the Varenne tokamak machine are underway (for details see Alternate Energy Section).

Marketing efforts led to sales of the overhead-groundwire power tap in Peru and of the Institute's digital power system analysis programs to the Central Electricity Authority in India. In addition to increased participation in international technology transfer fairs in 1983 IREQ published a brochure on the research undertaken by the Institute, as well as a newsletter, Information IREQ.

Ontario Hydro

R & D expenditures by Ontario Hydro totalled $58 million in 1983. Environmental protection continued to be a focus of activity in 1983. Acid rain studies were focussed on poorly understood processes such as dry deposition and cloud pollutant interactions and on modelling of long range transport. An instrument package was assembled and used for the first time to measure the dry deposition of acidic gases. A model of long range atmospheric transport was adopted for use in estimating the contribution of emissions to acid depositions. Behavioural systems that use lights, poppers and air bubbles to discourage fish from entering power plant intakes were developed and tested successfully. A new, flat, slotted intake, designed to reduce fish capture, was developed for Darlington generating station. Development of a new process for treatment of polychlorinated biphenyl - contaminated insulating oil and its conversion to oil of re-usable quality was completed. A mobile PCB processing plant was designed and is expected to be ready for commissioning in 1984. Studies on vegetation control are ongoing and are expected to lead to improvement of vegetation control and reduction of undesirable environmental impact. Research into the behaviour of radioactive emissions in the environment and the protection of workers against toxic substances continued in 1983. A meteorological survey was carried out at Pickering generating station in order to determine the frequency of unusual dispersion conditions, and preliminary plans were prepared for dispersion experiments under these conditions. Studies of the behaviour of tritium in the atmosphere continued and field tests of the rate of removal at the air-soil interface were carried out.

Under contract with Energy Mines & Resources, Ontario Hydro has undertaken to determine the effect on the Canadian economy of losses in energy, materials and equipment that result from friction and wear of surfaces in relative movement. Research in this area could reduce losses of this kind in Canada by an amount in the range from $500 million to $2 billion annually.

The Chemical Section completed a project to develop and demonstrate a process to clean coals to very low ash levels. This process could provide suitable coal at economic cost to replace oil for firing Lennox generating station when it is again required for power production. This project was co-funded by the Electric Power Research Institute of the United States. Other projects included a program to develop lightweight storage batteries that use conducting polymers as the active electrode materials, and an investigation of technical feasibility that shows that activation of helium - 3 in the neutron flux of a CANDU reactor, will enhance production of tritium for fusion and other appications.

A number of metallurgical research projects aimed at evaluation and improvement of the long term performance of zirconium alloys used in CANDU reactors are ongoing. These projects include investigations of microstructural strengthening mechanisims, studies of irradiation-induced deformation phenomena, evaluations of crack initiation and growth susceptibilities, and development of techniques for remote inspection of pressure tubes. The value of these projects was brought into focus by the rupture of the pressure tubes at Pickering units 1 and 2. The expertise, equipment and capabilities developed over the years were invaluable in providing short term aid and will be used to define longer term programs aimed at repair of units 1 and 2 and at evaluation of its relevance for other CANDU reactor units.

Electrical R & D continued in the following areas: reduction of costs for overhead lines, investigation of new technologies such as load management and system automation for distribution systems. A three year R & D Program resulted in the final design of the M-9 plenum heater for converting oil furnaces to hybrid operation. Research is ongoing on the technical and economic feasibilities of reducing heating costs through improvement of building performance, proper sizing of furnaces, the use of heat pumps and recovery of waste heat.

Saskatchewan Power

R&D expenditures by Saskatchewan Power totalled $3.15 million in 1983. Laboratory and field tests are under way on air-to-air and water source heat pump systems. The purpose is to determine the operational characteristics of these systems and their ability to meet typical residential space heating loads in Saskatchewan. They are being investigated as possible alternatives to conventional heating equipment in rural residences that do not have access to natural gas supplies.

Methods are being evaluated for using fly ash to remove pollutants from flue gases emitted from coal-burning power stations. One method under study involves the stripping of sulphur dioxide from flue gases using a dry sorbent material derived from fly ash. This holds promise for controlling environmental pollution in a less expensive, more efficient manner.

The problems in analysis of electric system operation during disturbances have been linked to a lack of data. As no commercial hardware was available, the design and construction of a suitable recording device was undertaken, and the resulting recorder was installed at a major SPC switching station and monitored for two years. In 1983, a revised design was produced to further improve the flexibility of the recorder. The corporation plans to install three of these recorders at key locations to provide additional information to assist in efficient operation of the electric grid.

Manitoba Hydro

Manitoba HVDC Research Centre, established in late 1981, is co-operatively sponsored by Manitoba Hydro, University of Manitoba, Teshmont Consultants Inc., Federal Pioneer Limited, and the Province of Manitoba, all of which provide staff and facilities to the Centre. Initial funding has been provided

by the Manitoba Government, totalling $3.75 million over the first five years, and by Manitoba Hydro, $1.25 million over the same period. Any additional financing required will be obtained by borrowing. The Centre expects to be self-supporting by 1986. During 1983, one of the projects undertaken by the Centre was a study for the National Research Council on the long term statistical measurement of radio interference and other corona related phenomena on the Nelson River HVDC transmission system. Other projects included the applications of fibre optics in overground wires on HVDC transmission lines, a study of vibration in high voltage transmission line structures and a research and development study in the field of HVDC system simulation utilizing microprocessor based tehcnology.

B.C. Hydro

R & D expenditures by British Columbia Hydro totalled $6.5 million in 1983. B.C. Hydro's research and development organization performs chemical, material and electrical research. The corporation also researches wind generation of electricity, geothermal energy, thermography, coal liquifaction and pressurized fluidized bed combustion. In addition, testing is carried out for government agencies and industry on insulating oils, high voltage systems, generator insulation systems, scanning electron microscopes and non-destructive materials. B.C. Hydro is presently investigating the tidal power generation potential of the Queen Charlotte Islands.

Electrical research in the research group comprises: distribution and utilization; electronics and control; high voltage transmission; insulation studies and system studies.

BC Hydro research scientists, working along near parallel paths with their counterparts at Ontario Hydro, have taken a major step towards the elimination of polychlorinated biphenyls (PCB's). In March 1983 the two utilities signed a co-operative agreement that calls for the sharing of information and patents to speed up the practical application of PCB destruction processes developed over the past two years.

BC Hydro is designing a mobile PCB destruction plant that can be taken to various field installations, thus eliminating the need to transport PCB's over long distances.

Canadian Electrical Association (CEA)

The CEA's research program totalled to $12.5 million in 1983, including co-funding of $4.2 million. These resources were allocated among committees as follows: $3.4 million to the generation program; $3.6 million to the transmission systems program; $3.0 million to the distribution program; and $1.7 million to utilization and conservation. $0.8 million was allocated to contract overhead expenditures.

The Generation Committee carries out work in three main areas: fossil and nuclear plants, hydro-electric plants, alternate energy and energy management. A total of 18 projects were completed during 1983 and 27 new projects were initiated. The largest project committed in 1983 was a co-funded proposal with TransAlta Utilities for participation in the Rockwell

Combustor Program. Indications are that this combustor, when fitted to existing coal or oil-fired boilers, will enable dramatic reductions in SO_x and NO_x emissions. This combustor would also allow conversion from oil-fired plant to coal-fired. Other highlights in 1983 included the completion of a study related to the emissions from thermal power plants, a study of the formation of ice covers on rivers downstream of hydro electric plants, presentation, at a symposium in Brazil, of a paper on Canada's research and development program for large hydraulic generation plants, and the initiation of a 10 year plan for combustion research which identified fluidized bed combustion, burner development and advanced ignition systems as the three most important areas of research.

The Transmission Program is aimed at a broad range of research in the areas of overhead and underground transmission. It seeks to improve existing technologies to meet growing capacity requirements and increasingly strict environmental constraints.

Fourteen new projects were intiated in 1983, 12 studies were granted funding extensions, and 6 position papers and state of the art studies were commissioned. The transmission program continued its participation, along with certain American and Canadian utilities, in the development of the electromagnetic transients program, a common tool used worldwide for digital simulation of power systems for insulation co-ordination studies. The R & D effort has been directed toward areas with potential for increased utilization and activity, e.g., mechanical performance of conductors and damping systems, increased loading of power transformers, lightning and earth resistivity studies and cable circuit capacities.

The Distribution Program is geared to the identification of potential electric distribution system problems and the formulation of appropriate research projects for their solution. Essential ingredients of the program are position papers and state-of-the-art studies, which help make expert advice available for sound definition of the specific R & D solutions required. In 1983, 16 new projects were initiated and 17 others received further funding. The projects included: salt fog tests on polymer insulators of distribution class; the development, demonstration and evaluation of SF6 insulated amorphous metal core distribution tranformers; infra-red thermogrphy for distribution systems, and the application of robotics to distribution systems. The research on new species for wood poles received an extension of time and money to produce a supplementary report on the durability of treated spruce poles. In 1984, preliminary research on the application of robotics to distribution sytems is expected to identify economies and efficiencies. Research on cold load pick-up, along with the results of a study on the simulation of electrical loads on a distribution system are expected to lead to an expansion of these studies. Additional work is expected to be undertaken on the amorphous metal transformer core which should result in the production of more efficient low cost transformers.

The Utilization and Conservation program is divided into two main areas of activity:

(1) that relating to the consumer;
(2) that relating to the utility.

These areas are highly interactive, so the program aims to develop energy efficient applications which will be beneficial both to the consumer and to the utility. In 1983 there was a major shift from a conservation mode to one where both utilization and conservation play an equally important part. Thirty-nine research projects were considered by the committee in 1983, under the broad headings of load management, fuel substitution, energy efficiency and consumer attitudes versus utility policy. Eleven projects were initiated, along with position papers and state-of-the-art studies. A dual energy heating symposium was held in Toronto in October 1983, in co-operation with Ontario Hydro. The presentations concentrated on the experiences of various utilities in this area as well as the realized and future benefits for utilities and consumers. Current contracts which involve the active participation of manufacturers in the development and production of new and improved products and equipment include: commercialization of improved air source heat pumps, residential heat recycle water heater development, higher ampacity battery development, and a study of illumination with high pressure sodium lamps in a prism guide.

In 1984, the committee will provide increased funding to study the potential uses for the extensive surplus capacity resulting from the recent slow-down in load growth and more emphasis will be placed on technology transfer to industry, especially where products have industrial applications. Pilot project installations of successful research are being pursued and will be cited in 1984.

ENVIRONMENTAL ISSUES

Generation and distribution of electricity affects the environment in a variety of ways. The electric utility industry faces several important environmental issues regarding generation, probably the most important being the relationship between sulphur emissions from sources such as coal-fired generating stations and acid rain. Two other issues of concern are radioactive waste management and the potential impacts of climate changes induced by increased levels of carbon dioxide (CO_2) in the atmosphere.

1. Acid Rain

The term acid rain refers to the problem caused by emissions of sulphur and nitrogen oxides (SO_2 and NO_x) which combine with atmospheric moisture to produce sulphuric acid and nitric acid. These acids return to the ground as acid rain or acid snow.

It also encompasses dry deposition, whereby dry particles of SO_2 and NO_x fall to the earth and the particles become acidic when combined with surface water. These two processes occur with roughly equal frequency.

The release of elements which produce acid rain results from activities in various industrial and non-industrial sectors. These include transportation, non-ferrous smelting, non-utility and utility boilers.

Electric utility contribution to this problem will be significantly reduced in Canada, beginning in 1985. Ontario Hydro is by far the most serious utility contributor to the problem, as it produced 42% of the coal-fired generation in Canada in 1983 from coal with a high sulphur content upwind from areas most susceptible to acid rain damage. In 1985 Ontario Hydro expects its coal-fired generation to decrease by 24% relative to 1983, (having increased 12% in 1984 as a result of the outages at Pickering units 1&2) and by 73% by 1990. The reduction will result from increased nuclear generation and from hydro electricity purchases from Quebec. Alberta and Saskatchewan together produced 51% of the coal-fired generation in 1983, from coal with a very low sulphur content which causes very few acid rain problems. The Maritimes produced 6% of the total coal used for electricity generation from coal with a very high sulpher content but prevailing westerly winds blow most of the emission off shore.

Acid rain has far-reaching implications for all aspects of the environment. It alters the acidity levels of soil and of water bodies, causing changes in the level and quality of aquatic life and vegetation. While the complexities of acid rain phenomena are not completely understood, the circumstantial evidence linking man-made emissions and environmental loadings is convincing. Of particular concern in Canada are the potential impacts on forests, both their productivity and health, and on fish populations.

Acid rain is not a localized phenomenon because SO_2 and NO_x are transported over long distances through the atmosphere. While there is particulate and gaseous deposition in the vicinity of an emitting source, past practice of building taller stacks to relieve local pollution problems has aggravated regional, interprovincial and international problems.

Approximately 4 million metric tonnes of SO_2 are deposited in Canada annually from sources in the United States and between 500-700 thousand tonnes are deposited in the U.S. from Canadian sources. Approximately 60 per cent of Canadian emissions from east of Manitoba come from non-ferrous smelters and about 15 per cent from thermal power stations. The balance is mainly from industrial processes and non-utility fuel use.

In February 1983 a series of U.S.-Canada Working Group reports on trans-boundary air pollution were published. These focused primarily on acid rain. The bilateral Working Groups were formed under a Memorandum of Intent(MOI) signed by both governments in August 1980. Groups were composed of Canadian federal and provincial scientists and American scientists from a number of federal agencies. They assembled and analyzed available information on the nature and causes of acid rain and worked on solutions to the problem. The reports confirm that damage is occurring in areas vulnerable to acid rain and that this is attributable mainly to wet and dry deposition of sulphur compounds.

The reports concur that an environmental loading rate of 20 kilogram per hectare per year (Kg/Ha/year) wet sulphate deposition is related to damage in the vulnerable areas. No effect is reported below this loading rate. Canadian and U.S. groups differ on the appropriateness of recommending a loading maximum of 20 Kg/Ha/year. The U.S. groups maintain the recommendation is premature.

The Working Group examined transport of air pollutants between source region and receptor areas. They show acid rain occurs in eastern North America within and downwind of major source regions of oxides of sulphur and nitrogen.The evidence suggests that much of the acidic deposition in the northeastern United States and eastern Canada is man-made, based on the geographical association between the regions of the largest North American emissions of sulphur and nitrogen oxides and the regions of the largest wet deposition of sulphur and nitrogen oxides.

The Working Group tried to determine the origin of the sulphur falling on various parts of eastern North American through modelling. However, reliability of current models is uncertain when predicting the results of alternative emissions patterns (i.e. the change in deposition that would result from change in emissions). The Working Group on impact assessment recommended further research to assess the economic benefits of controlling acid rain pollutants.

Despite these uncertainties the Canadian members of the Working Group stressed the serious nature of the acid rain problem and the need for regulatory action to prevent further damage.

Canada - U.S. Negotiations

In 1982, Canada proposed a 50 per cent reduction in Canadian sulphur dioxide emissions east of Saskatchewan by 1990, contingent upon similar actions in the eastern U.S. The response has been that this commitment would be premature as it questions the adequacy of the scientific data. Depressed economic conditions also deter U.S. reductions. However the U.S. government increased acid rain research funds by 28 per cent, to $23 million in 1983, a reflection of their view that more research is needed before increasing controls. In early 1984, Canadian Environment Ministers agreed to unilateral 50 percent reduction in emissions by 1994.

In the United States, there exist approximately 87 flue gas desulphurization units, or 'scrubbers', installed on fossil-fired generating units and an additional 22 are currently being installed. Regulations of the Environmental Protection Agency (EPA) require new fossil-fired plants to have scrubbers.

These standards do not apply to existing stations or those converting from oil to coal. This policy is consistent with that of other countries faced with acid rain problems. In these countries retrofitting scrubbers to older plants or to converted plants is seen as uneconomical.

Response to Acid Rain

In Canada measures are being taken to curb emission levels. The federal and Nova Scotia governments recently announced a $8.0 million pilot project to test fluidized bed combustion of coal as an alternative to scrubbers. The experiment is being conducted at the Nova Scotia Power Corporation's Point Tupper generating station.

Under the National Energy Program, funding for conversions from oil to coal-fired generating stations is contingent upon environmental acceptability. It is within provincial jurisdiction to control emissions. Federal authority exists only over international agreements.

The Ontario Government initiated a program aimed at a 43 per cent emissions reduction by 1990. The program includes controls on contributors such as International Nickel Company (INCO) and Ontario Hydro. The utility is committed to emission reduction using a range of control options and technologies. In addition to purchasing only washed coal, Ontario Hydro blends Canadian and U.S. coal to reduce sulphur dioxide emissions by about 15 per cent. Total utility emissions should be halved by 1990.

In Alberta maximum particulate emission limits have been set. Limits have also been set on ambient ground level concentrations of SO_2, NO_x, and particulates. To comply with the regulations, Alberta Power will install electrostatic precipitators at the Sheerness Station now under construction. Retrofit precipitators will be installed on Battle River units one to four. An electrostatic precipitater has been installed on unit five.

Capital costs of environmental requirements at the two stations totalled approximately $86 million. Operating and maintenance costs for monitoring total approximately $170,000 per annum.

Scientific research into acid rain is carried out by various Federal departments in Canada. These include the Departments of the Environment, Fisheries and Oceans, National Health and Welfare, and Energy, Mines and Resources. These research and development programs were expanded in 1980 with increases in funding over four years of $10.0 million to Environment, $12.4 million to Fisheries and Oceans, and $3.7 million to Health and Welfare.

These departments contribute to the Federal Long-Range Transport of Air Pollutants (LRTAP) Program. The program has three sections: Scientific Studies, Information Projects and Control Strategies Program Studies. Coordination of the program is provided by the Interdepartmental LRTAP Committee. The program enhances the scientific and technical understanding of LRTAP and acidic precipitation. Expansion of the program is being considered.

Effects of acid rain/LRTAP are being researched simultaneously by the provinces, academic institutions and the private sector. The Federal-Provincial Management Board coordinates the activities of the federal and provincial governments in emission reductions, research and public information.

2. Radioactive Waste Management

Since 1976, Atomic Energy of Canada Ltd. (AECL) has directed a research program on the permanent passive disposal of irradiated fuel waste in stable crystalline rock of the Canadian Shield. Preliminary results from this program indicate nuclear fuel waste can be safely disposed in this manner. Approximatly 6,000 tonnes of used fuel has been generated, and is safely stored using accepted methods, at the reactor sites.

This research is a joint program performed under the terms of the Canada/Ontario agreement of June 1978. Under this agreement Ontario Hydro is responsible for research on storage and transportation of irradiated fuel. A further Federal/Ontario agreement in August 1981 defined the evaluation process leading to acceptance of the proposed disposal concept.

The concept evaluation process consists of a regulatory review, public hearings and governmental decision, and is scheduled for completion by 1981. Site selection for an actual disposal facility will not proceed until government approval is obtained for the disposal concept.

The research program receives approximately $35 million per annum in funding. The program includes:

1) generic research and development of technologies for the interim storage and transportation of used fuel;

2) immobilization of used fuel and recycle wastes in containers which provide isolation from ground water;

3) geoscience research to characterise geologic features relevant to selection of future disposal sites;

4) environmental research and environmental and safety assessment to estimate the environmental and health effects of storage, transport, immobilization and disposal of nuclear fuel wastes.

An underground research laboratory is being constructed near Lac du Bonnet, Manitoba and will be complete by 1986. This facility will be used to verify predictions of geological and hydro-geological conditions. It will provide underground space for in situ experiments to verify data from computer models.

In 1982, the Federal Government announced new initiatives for the other two categories of Canadian radioactive waste, namely uranium tailings and low-level radioactive waste.

Approximately, 120 million tonnes of uranium tailings has been generated to date, representing 2 per cent of the mining wastes deposited in Canada. This material is subject to monitoring and control of harmful effluents. A $9.5 million federal research program will study the long term effects of uranium tailings, expedite development of technology to maintain the safety of tailings deposits after closing of the mining operations.

The research program consists of measurement, modelling and disposal technology areas. Measurement will examine operating tailings and systems abandoned 20 years ago for hydrological, geochemical and environmental effects. Modelling will develop and verify predictive scientific procedures to determine future effluents and their health and environmental effects. Disposal technology will examine the effects of different rehabilitation and disposal technologies on long term health and environmental factors. The technologies being considered are landscaping and revegetation, variations in the method of depositing tailings both on land and underwater, and removal of the contaminants.

In October 1982, AECL formed a new office to carry out the federal responsibilities of low-level radioactive waste management. These responsibilities include the completion of remedial work for cleanup of historic waste problems, research and evaluation of options available for disposal, and ensuring that a collection, treatment and safe disposal service is made available on a commercial basis. Low-level radioactive waste is produced in research facilities, in hospitals, in industrial plants, and in nuclear electricity generating stations.

Approximately 1,000,000 tonnes of low-level radioactive wastes have been generated in Canada to date. Most wastes of this kind are in safe storage under supervision. Although this storage can be continued for many years, permanent disposal will eventually be required.

The Low-Level Radioactive Waste Management Office is currently undertaking a project to remove several thousand tons of radium contaminated soil from about 40 residential properties in Scarborough, Ontario and is also involved in efforts to remove thorium containing slag from two industrial properties in Surrey, B.C. In addition the Office is developing scenarios and analysing strategy for the establishment of disposal facilities for wastes which are produced on a continuing basis.

Research programs for the management and disposal of the low-level radioactive wastes are being conducted by AECL, Ontario Hydro and Eldorado Resources Limited. The programs seek to reduce the volume and immobilize waste products. They evaluate the potential use of three types of disposal facilities - sanitary landfill, engineered facilities at shallow depth, and underground caverns.

With these three programs the federal government is addressing all aspects of the management and disposal of radioactive waste in Canada. Much work remains before a complete operating system is in place. The cooperation and support of provincial and municipal governments, industry and the public will be required to reach that goal.

Selected Bibliography.

Electric Power Statistics, Volume I - Annual Electric Power Survey of Capability and Load (Catalogue No. 57-204)

Presents the results of the annual electric power survey of capability and load and covers all producers of electrical energy in Canada which generate or will generate 20 million kWh per annum or more during the forecast period.

Electric Power Statistics, Volume II - Annual Statistics (Catalogue No. 57-202)

Includes various statistics, on an annual basis, for electric utilities and industrial establishments including installed capacity, generation,

supply and disposal, number of customers, revenue, energy transfers, domestic and farm service, and transmission mileage. Statistics on fuels, employees, wages and salaries, assets and liabilites, income account, taxes and capital and repair expenditures are also included for electric utilities.

Electric Power Statistics, Volume III - Inventory of Prime Mover and Electic Generating Equipment (Catalogue No. 57-206)

Provides a detailed listing of prime mover and generating equipment above 500 kW, on an annual basis.

Electric Power Statistics, Monthly (Catalogue No. 57-001)

Presents, on a monthly basis, preliminary electrical energy statistics.

Electricity Bills for Domestic, Commercial and Small Power Service (Catalogue No. 57-203)

Based on the rate schedules supplied by the power companies and municipalities responsible for the distribution of electrical energy in the cities and towns covered in an annual survey. Monthly bills are computed to show the revenue according to the distributors from the sale of definite quantities of electricity used for specific purposes.

Quarterly Report on Energy-Supply Demand in Canada (Catalogue No. 57-003)

Energy balance sheets in both natural units and terajoules for fuel types by region. Each balance sheet shows data on production, imports, exports, interregional movements, conversion from one energy form to another, and consumption by consuming sectors.

The following publications are available from distributors of Canadian government publications, or from the OECD Publications Office, 2 rue André-Pascal, 75 Paris 16e, France.

Organization for Economic Cooperation and Development, Survey by the Energy Division, Annual Survey of Electric Power Equipment, Situation and Prospects.

Combines the results of two studies carried out by the OECD:

- Survey of the Energy Division in the development of capital equipment in the electricity supply industry and its technical characteristics (Part One)

- Survey of the Special Committee for Machinery on the trends of deliveries, orders on hand and production capacity of European manufacturers of heavy equipment for power stations (Part Two)

These two complementary surveys show the situation as of January 1st and give an indication of trends for the next 5 years.

Organization for Economic Cooperation and Development, Energy Division, The Electricity Supply Industry

Annual general review of the electricity supply industry in OECD countires in the last 2 years and provides an outlook for the following five years.

Organization for Economic Cooperation and Development, Economic Statistics and National Accounts Division, Statistics of Energy

Presents annually a set of basic statistics on production, trade consumption, etc. for each source of energy, following a standard pattern so that they are presented in consolidated and comparable form.

OECD Energy Statistics 1972/1982
OECD Energy Balances 1971/1982
OECD Oil and Gas Statistics 1981/1982.

In addition, more detailed information on individual foreign countries can be obtained by contacting individual electric utilities or government agencies.

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3. THE ELECTRICITY AND FLUID EXPORTATION ACT, April 27, 1907.

4. ELECTRICITY AND FLUID EXPORTATION REGULATIONS, PC 1954-1522, October 6, 1954.

5. ELECTRIC POWER STATISTICS CATALOGUE 57-202 ANNUAL, various issues.

6. FOREIGN TRADE IN GAS AND ELECTRICITY IN NORTH AMERICA, A LEGAL AND HISTORICAL STUDY, John T. Miller Jr., Praeger Publishers, New York, N.Y., 1970.

7. INTERCONNECTIONS BETWEEN CANADA AND THE UNITED STATES; E.S. Bell, A.J. Stremlaw and G. Yorke Slader, Electrical Engineering Branch, National Energy Board, Canada; presented to United Nations Economic and Social Council, Economic Commission for Europe, Committee on Electric Power, Delphi and Athens, Greece, May 1975.

8. NATIONAL ENERGY BOARD ACT, July 1959.

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11. ORDER IN COUNCIL P.C. 1957-1386.

12. POTENTIAL BENEFITS AND COSTS OF CANADIAN ELECTRICITY EXPORTS - VOLUME 1, Canadian Energy Research Institute, Calgary, October 1982.

13. FIRST REPORT OF THE ROYAL COMMISSION ON ENERGY, October 1958.

14. SECOND REPORT OF THE ROYAL COMMISSION ON ENERGY, July 1959.

15. STATEMENT OF NATIONAL POWER POLICY by the Honourable Mitchell Sharp, Minister of Trade and Commerce, Government of Canada, October 8, 1963.

TABLE A1

INSTALLED CAPACITY AND ELECTRICAL ENERGY CONSUMPTION IN CANADA, 1920-1983

Year	INSTALLED CAPACITY					Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin	Load Factor
	Thermal Conventional	Thermal Nuclear	Sub-Total	Hydro	Total					
			(MW)			(a) (GWh)	(b) (MW)	(c) (MW)	(d) %	(e) %
1920	300	–	300	1 700	2 000	–	–	–	–	–
1930	400	–	400	4 300	4 700	19 468	2 222	–	–	–
1940	500	–	500	6 200	6 700	33 062	3 774	–	–	–
1950	900	–	900	8 900	9 800	55 037	6 283	–	–	–
1955	2 100	–	2 100	12 600	14 700	81 000	9 247	12 536	17	74
1960	4 392	–	4 392	18 657	23 049	109 302	12 477	17 264	34	72
1961	5 072	–	5 072	19 019	24 091	110 950	12 666	18 353	31	69
1962	5 609	20	5 629	19 338	24 967	116 135	13 257	18 937	32	70
1963	6 180	20	6 200	20 101	26 301	121 510	13 871	20 783	27	67
1964	6 694	20	6 714	20 313	27 027	133 949	15 291	22 516	20	68
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	21	68
1966	8 307	20	8 327	22 438	30 765	156 956	17 917	25 921	19	69
1967	9 373	240	9 613	23 353	32 966	165 812	18 928	27 812	19	68
1968	10 711	240	10 951	24 957	35 908	176 841	20 187	30 300	19	67
1969	12 321	240	12 561	27 031	39 592	189 522	21 635	32 092	23	67
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	24	67
1971	14 504	1 570	16 075	30 601	46 676	212 882	24 302	35 720	31	68
1972	15 318	2 126	17 444	32 500	49 944	231 557	26 433	38 921	28	68
1973	17 711	2 400	20 111	34 266	54 376	249 298	28 459	42 699	27	67
1974	18 085	2 666	20 751	36 779	57 530	266 956	30 747	42 528	35	72
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 537	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	39	66
1980	27 853	5 866	33 719	47 919	81 634	340 069	38 821	59 170	38	66
1981	28 493	5 600	34 093	49 216	83 308	346 333r	39 536r	59 237r	41	67r
1982r	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	37	63
1983*	29 841	7 747	37 588	51 512	89 101	359 454	41 034	66 866	33	61

(a) 1920-55: figures are approximate, computed using actualStatistics Canada data for stations generating energy forsale to which have been added estimates for stationsgenerating entirely for own use. 1920-55 Canadian EnergyProspects (Royal Commission on Canada's Economic Prospects)John Davis, 1957. 1956-81, Statistics Canada Publication.

57-202.

(b) Average Demand = Energy Consumption - 8 760 (hrs/yr).

(c) Statistics Canada Publication 57-204.

(d) Reserve margin = (Installed capacity - Peak Demand) / Peak Demand

(e) Load Factor = Average Demand - Peak Demand.

* Preliminary Data.

r Revised Figures.

TABLE A2

INSTALLED AND PROPOSED GENERATING CAPACITY, 1983 (MW)

	Hydro	Nuclear	Conventional Thermal*	Total	% of Canadian Total
Newfoundland	6 296	-	752	7 048	7.9
Prince Edward Island	-	-	118	118	**
Nova Scotia	363	-	1 654	2 017	2.3
New Brunswick	901	680	1 888	3 469	3.9
Québec	22 732	951	1 149	24 832	27.9
Ontario	7 167	6 116	13 569	26 852	30.1
Manitoba	3 641	-	503	4 144	4.7
Saskatchewan	576	-	2 046	2 622	2.9
Alberta	734	-	6 093	6 827	7.7
British Columbia	8 998	-	1 888	10 886	12.2
Yukon	58	-	40	98	**
Northwest Territories	47	-	141	188	**
Canada Total			150	150	
At Dec. 31, 1983***	51 513	7 747	29 841	89 101	-
Percent of Total Capacity, End 1983	58	9	33	100	-
Net additions During 1983***	1 505	1 201	884	3 590	-
Planned additions During 1984	4 324	2 594	759	7 677	-

* Details provided in Table A3. Conventional thermal includes steam, gas turbine, internal combustion.

** Less than 0.5%.

*** Preliminary Data.

TABLE A3

CONVENTIONAL THERMAL CAPACITY BY PRINCIPAL FUEL TYPE. PRELIMINARY FIGURES AS AT DECEMBER 31, 1983 (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*		Oil	Gas		Oil	Gas		Coal	Oil	Gas	Other*	Total
Newfoundland/ Terre-Neuve	–	503	–	–	503	170	–	170	79	–	79	–	752	–	–	752
Prince Edward Island/ Ile-du-Prince-Edouard	–	70	–	–	70	41	–	41	7	–	7	–	118	–	–	118
Nova Scotia/ Nouvelle-Ecosse	787	661	–	–	1 448	205	–	205	1	–	1	787	867	–	–	1 654
New Brunswick/ Nouveau-Brunswick	285	1 535	–	40	1 860	23	–	23	5	–	5	285	1 563	–	40	1 888
Québec	–	630	–	10	640	363	–	363	146	–	146	–	1 139	–	10	1 149
Ontario	9 150	2 320	1 317	85	12 872	506	181	687	4	6	10	9 150	2 830	1 504	85	13 569
Manitoba	419	–	4	24	447	24	–	24	32	–	32	419	56	4	24	503
Saskatchewan	1 775	–	128	21	1 924	–	104	104	18	–	18	1 775	18	232	21	2 046
Alberta	4 073	66	1 279	107	5 525	–	524	524	14	30	44	4 073	80	1 833	107	6 093
British Columbia/ Colombie-Britannique	–	154	1 038	234	1 426	185	154	339	105	18	123	–	444	1 210	234	1 888
Yukon	–	–	–	–	–	–	–	–	40	–	40	–	40	–	–	40
N.W.T/T.N.-O.	–	1	–	–	1	–	–	–	140	–	140	–	141	–	–	141
CANADA	16 489	5 940	3 766	521	26 716	1 517	963	2 480	591	54	645	16 489	8 048	4 783	521	29 841

* Mainly wood wastes and black liquor.

TABLE A4

ELECTRICAL ENERGY PRODUCTION BY PRINCIPAL FUEL TYPE, PRELIMINARY FIGURES 1983 (GWh)

	CONVENTIONAL THERMAL								% Generated By	
Province	Coal*	Oil*	Gas*	Total	Nuclear	Hydro	Total	% of Total Generation	Utilities	Industrial Establishments
Newfoundland	–	604	–	604	–	39 390	39 994	10.1	98.9	1.1
Prince Edward Island	–	11	–	11	–	–	11	0.0	100.0	0.0
Nova Scotia	3 298	1 875	–	5 173	–	995	6 168	1.6	94.5	5.5
New Brunswick	973	2 766	–	3 739	4 759	3 090	11 588	2.9	95.4	4.6
Québec	–	137	–	137	1 990	108 439	110 566	28.1	83.4	16.6
Ontario	35 466	493	1 892	37 851	39 472	40 495	117 818	29.8	96.7	3.3
Manitoba	110	71	10	191	–	21 893	22 084	5.6	99.7	0.3
Saskatchewan	7 604	50	488	8 142	–	2 211	10 353	2.6	96.6	3.4
Alberta	24 071	110	3 330	27 511	–	1 480	28 991	7.3	90.9	9.1
British Columbia	–	1 367	999	2 366	–	44 390	46 756	11.8	75.5	24.5
Yukon	–	22	–	22	–	221	243	0.1	100.0	.0
Northwest Territories	–	175	–	175	–	258	433	0.1	94.4	5.6
CANADA	71 522	7 681	6 719	85 921	46 221	262 862	395 005	100.0	90.3	9.7

* Estimated values.

Source Statistics Canada

TABLE A5

PROVINCIAL ELECTRICITY IMPORTS AND EXPORTS (GWh)

Province	Year	Interprovincial Trade			International Trade			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Newfoundland	1983	31 234	-	31 234				31 234
	1982	35 777	-	35 777	-	-	-	35 777
	1981	35 941	-	35 941	-	-	-	35 941
Prince Edward Island	1983	-	519	-519	-	-	-	-519
	1982	-	476	-476	-	-	-	-476
	1981	-	484	-484	-	-	-	-484
Nova Scotia	1983	121	723	-602				-602
	1982	133	216	-83	-	-	-	-83
	1981	125	317	-192	-	-	-	-192
New Brunswick	1983	1 245	4 112	-2 867	5 265	24	5 241	2 374
	1982	692	3 746	-3 054	3 029	71	2 958	-95
	1981	801	3 846	-3 045	3 246	54	3 192	147
Québec	1983	9 371	31 290	-21 919	10 128	8	10 120	-11 799
	1982	9 386	35 833	-26 447	8 530	7	8 523	-17 924
	1981	10 209	36 098	-25 889	8 313	7	8 306	-17 583
Ontario	1983	59	6 336	-6 277	12 207	369	11 838	5 561
	1982	60	6 845	-6 785	11 168	403	10 765	3 980
	1981	59	7 705	-7 646	11 310	343	10 967	3 321
Manitoba	1983	2 555	1 213	1 342	5 994	19	5 975	7 317
	1982	2 460	1 088	1 372	5 255	214	5 041	6 413
	1981	2 508	1 066	1 442	3 681	194	3 487	4 929
Saskatchewan	1983	1 210	1 601	-391	81	84	-3	-394
	1982	1 087	1 388	-301	60	31	29	-272
	1981	1 068	1 290	-222	-	-	-	-222

TABLE A5 (cont'd)

PROVINCIAL ELECTRICITY IMPORTS AND EXPORTS (GWh)

Province	Year	Interprovincial Trade			International Trade			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Alberta	1983	198	346	-148	–	2	-2	-150
	1982	189	447	-258	–	2	-2	-261
	1981	262	169	93	–	2	-2	91
British Columbia	1983	341	196	145	4 633	2 251	2 382	2 527
Colombie-Britannique	1982	444	189	255	6 171	2 119	4 052	4 307
	1981	165	262	-96	8 821	897	7 924	7 828
Yukon	1982	–	–	–	–	–	–	–
	1981	–	–	–	–	–	–	–
N.W.T.	1982	–	–	–	–	–	–	–
	1981	–	–	–	–	–	–	–
CANADA	1983				38 308	2 757	35 551	35 551
	1982	–	–	–	34 214	2 848	31 366	31 366
	1981	–	–	–	35 372	1 497	33 876	33 876

Source Statistics Canada.

TABLE A6

GENERATION CAPACITY BY TYPE (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total End 1982	502.60	170.39	79.28	-	752.27	6 210.26	6 962.53
Additions 1983	-	-	-	-		85.72	85.72
Total End	502.60	170.39	79.28	-	752.27	6 295.98	7 048.25
Additions Proposed							
1984	-	-	-	-	-	5.51	5.51
1985	-	-	-	-	-	127.00	127.00
1986	-	-	-	-	-	-	-
Total End 1986	502.60	170.39	79.28	-	752.27	6 428.49	7 180.76
PRINCE EDWARD ISLAND							
Total End 1982	70.50	40.85	6.89	-	118.24	-	118.24
Additions 1983	-	-	-	-	-	-	-
Total End 1983	70.50	40.85	6.89	-	118.24	-	118.24
Additions Proposed							
1984	-	-	-	-	-	-	-
Total End 1984	70.50	40.85	6.89	-	118.24	-	118.24
NOVA SCOTIA							
Total End 1982	1 298.28	205.00	0.60	-	1 503.88	360.70	1 864.58
Additions 1983	150.00	-	-	-	150.00	2.50	152.50
Total End 1982	1 448.28	205.00	0.60	-	1 653.88	363.20	2 017.08
Additions Proposed							
1984	150.00	-	-	-	150.00	20.00	170.00
1985	-	-	-	-	-	-	-
1986	--	--	--	--	--	7.30	7.30
1987	--	--	--	--	--	--	--
1988	--	--	--	--	--	--	--
1989	--	--	--	--	--	--	--
1990	--	--	--	--	--	--	--
1991	300.00	--	--	--	300.00	--	300.00
Total End 1991	1 898.28	205.00	0.60	--	2 103.88	390.50	2 494.38

TABLE A6 (cont'd)

GENERATION CAPACITY BY TYPE (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEW BRUNSWICK							
Total End 1982	1 859.88	23.38	4.84	680.00	2 568.10	900.63	3 468.73
Additions 1983	-	-	-	-	-	-	-
Total End 1983	1 859.88	23.38	4.84	680.00	2 568.10	900.63	3 468.73
Additions Proposed							
1984	-	-	-	-	-	-	-
Total End 1984	1 859.88	23.38	4.84	680.00	2 568.10	900.93	3 468.73
QUEBEC							
Total End 1982	639.75	362.88	142.45	266.40	1 411.48	21 350.91	22 762.39
Additions 1983	-	-	3.90	685.00	688.90	1 380.73	2 069.63
Total End 1983	639.75	362.88	146.35	951.40	2 100.38	22 731.64	24 832.02
Additions Proposed							
1984	-	-	-	-	-	2 435.00	2 435.00
1985	-	-	-	-	-	586.00	586.00
1986	-	-	-	-	-	-	-
1987	-	-	-	-	-	-	-
1988	-	-	-	-	-	-	-
1989	-	-	-	-	-	-	-
1990	-	-	-	-	-	510.00	510.00
1991	-	-	-	-	-	1 275.00	1 275.00
1992	-	-	-	-	-	1 259.00	1 259.00
1993	-	-	-	-	-	594.00	594.00
1994	-	-	-	-	-	800.00	800.00
Total End 1994	639.75	362.88	146.35	951.40	2 100.38	3 0279.94	3 2380.32

TABLE A6 (cont'd)

GENERATION CAPACITY BY TYPE (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ONTARIO							
Total End 1982	12 871.98	659.19	10.02	5 600.00	19 141.19	7 131.24	26 272.43
Additions 1983	–	28.00	–	516.00	544.00	36.00	580.00
Total End 1983	12 871.98	687.19	10.02	6 116.00	19 685.19	7 167.24	26 852.43
Additions Proposed							
1984	206.00	–	–	2 594.00	2 800.00	–	2 800.00
1985	–	104.00	–	516.00	620.00	–	620.00
1986	–	–	–	781.00	781.00	–	781.00
1987	–	–	–	781.00	781.00	–	781.00
1988	–	–	–	881.00	881.00	–	881.00
1989	–	–	–	881.00	881.00	–	881.00
1990	–	–	–	–	–	–	–
1991	–	–	–	881.00	881.00	–	881.00
1992	–	–	–	881.00	881.00	–	881.00
Total End 1992	13 077.98	791.19	10.02	14 312.00	28 191.19	7 167.24	35 358.43
MANITOBA							
Total End 1982	447.00	23.80	32.12	–	502.92	3 641.10	4 144.02
Additions 1983	–	–	–	–	–	–	–
Total End 1983	447.00	23.80	32.12	–	502.92	3 641.10	4 144.02
Additions Proposed							
1992	–	–	–	–	–	255.00	255.00
1993	–	–	–	–	–	637.50	637.50
1994	–	–	–	–	–	382.50	382.50
1999	–	–	–	–	–	96.00	96.00
2000	–	–	–	–	–	288.00	288.00
2001	–	–	–	–	–	130.00	130.00
2002	–	–	–	–	–	520.00	520.00
2003	–	–	–	–	–	650.00	650.00
Total End 2002	447.00	23.80	32.12	–	502.92	6 600.1	7 103.02

TABLE A6 (cont'd)

GENERATION CAPACITY BY TYPE (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
SASKATCHEWAN							
Total End 1982	1 623.96	103.92	18.28	-	1 746.16	575.50	2 321.66
Additions 1983	300.00	-	-	-	300.00	-	300.00
Total End 1983	1 923.96	103.92	18.28	-	2 046.16	575.50	2 621.66
Additions Proposed							
1984	-	-	-	-	-	-	-
1985	-	-	-	-	-	84.00	84.00
1986	-	-	-	-	-	168.00	168.00
Total End 1986	1 923.96	103.92	18.28	-	2 046.16	827.50	2 873.66
ALBERTA							
Total End 1982	5 124.89	524.10	44.35	-	5 693.34	733.70	6 427.04
Additions 1983	400.00	-	-	-	400.00	-	400.00
Total End 1983	5 524.89	524.10	44.35	-	6 093.34	733.70	6 827.04
Additions Proposed							
1984	400.00	-	-	-	400.00	-	400.00
1985	-	-	-	-	-	-	-
1986	380.00	-	-	-	380.00	5.0	385.00
1987	380.00	-	-	-	380.00	-	380.00
1988	400.00	-	-	-	400.00	-	400.00
1989	400.00	-	-	-	400.00	-	400.00
1991	400.00	-	-	-	400.00	-	400.00
1991	400.00	-	-	-	400.00	-	400.00
1993	375.00	-	-	-	375.00	-	375.00
1995	-	-	-	-	-	759.00	759.00
1996	-	-	-	-	-	906.00	906.00
1997	-	-	-	-	-	151.00	151.00
1999	750.00	-	-	-	750.00	-	750.00
2000	750.00	-	-	-	750.00	-	750.00
Total End 2000	10 159.89	524.10	44.35	-	10 728.34	2 554.70	13 283.04

TABLE A6 (cont'd)
TABLEAU A6 (suite)

GENERATION CAPACITY BY TYPE (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
BRITISH COLUMBIA							
Total End 1982	1 425.64	339.20	122.93	-	1 887.77	8 997.86	10 885.63
Additions 1983	-	-	-	-	-	-	-
Total End 1983	1 425.64	339.20	122.93	-	1 887.77	8 997.86	10 885.63
Additions Proposed							
1984	-	-	-	-	-	1 843.00	1 843.00
1985	-	-	-	-	-	-	-
1994	-	-	-	-	-	142.00	142.00
1995	-	-	-	-	-	170.00	170.00
1996	-	-	-	-	-	165.00	165.00
1997	-	-	-	-	-	-	-
1998	-	-	-	-	-	450.00	450.00
1999	-	-	-	-	-	450.00	450.00
Total End 1999	1 425.64	339.20	122.93	-	1 887.77	12 217.86	14 105.63
YUKON							
Total End 1982	-	-	39.87	-	39.87	58.14	98.01
Additions 1983	-	-	-	-	-	-	-
Total End 1983	-	-	39.87	-	39.87	58.14	98.01
Additions Proposed							
1984						20.00	20.00
Total End 1984	-	-	39.87	-	39.87	78.14	118.01

TABLE A6 (cont'd)

GENERATION CAPACITY BY TYPE (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NORTHWEST TERRITORIES							
Total End 1982	0.60	-	138.28	-	138.88	47.36	186.24
Additions 1983	-	-	1.80	-	1.80	-	1.80
Total End 1983	0.60	-	140.08	-	140.68	47.36	188.04
Additions Proposed							
1984	-	-	2.82	-	2.82	-	2.82
Total End 1984	0.60	-	142.90	-	143.50	47.36	190.86
CANADA							
Total End 1982	25 865.07	2 452 70	639.91	6 546.40	35 504.08	50 007.40	85 511.48
Additions 1983	850.00	28.00	5.70	1 201.00	2 084.70	1 504.95	3 589.65
Total End 1983	26 565.08	2 480.71	645.61	7 747.40	37 588.78	51 512.35	89 101.13
Additions Proposed							
1984	756.00	-	2.82	2 594.00	3 352.82	4 323.51	7 676.33
1985	-	104.00	-	516.00	620.00	804.30	1 424.00
1986	380.00	-	-	781.00	1 161.00	173.00	1 334.00
1987	380.00	-	-	781.00	1 161.00	-	1 161.00
1988	400.00	-	-	881.00	1 281.00	-	1 281.00
1989	400.00	-	-	881.00	1 281.00	-	1 281.00
1990	-	-	-	-	-	510.00	510.00
1991	700.00	-	-	881.00	1 581.00	1 275.00	2 856.00
1992	400.00	-	-	881.00	1 281.00	1 514.00	2 795.00
1993	375.00	-	-	-	375.00	1 231.50	1 606.50
1994	-	-	-	-	-	1 324.50	1 324.50
1995	-	-	-	-	-	929.00	929.00
1996	-	-	-	-	-	1 071.00	1 071.00
1997	-	-	-	-	-	151.00	151.00
1998	-	-	-	-	-	450.00	450.00
1999	750.00	-	-	-	750.00	546.00	1 296.00
2000	750.00	-	-	-	750.00	288.00	1 038.00
2001	-	-	-	-	-	130.00	130.00
2002		-	-	-	-	520.00	520.00
2003	-	-	-	-	-	650.00	650.00
Total End 2003	32 006.08	2 584.71	648.43	15 943.40	51 182.62	67 403.16	118 610.78

TABLE A7

INSTALLED GENERATING CAPACITY EXPANSION IN CANADA BY STATION. MAJOR 1983 ADDITIONS AND PROJECTED 1984 - 2003

Province & Station	Type*	Additions in1983 (MW)	Year	Additions Proposed (MW)	Status	Proposed plant capacity (MW)
Newfoundland						
Upper Salmon	H	84.00			I	84.00
Topsail	H		1984	2.25	C	3.45
Lawn	H	0.65			I	0.95
Morris	H	1.07			I	1.07
Lookout Brook	H		1984	2.65	C	7.85
Cat Arm	H		1985	2 x 63.50	C	127.00
Petty Harbour	H		1984	2 x 0.30	P	5.61
Nova Scotia						
Fourth Lake	H	2.5			I	2.50
Annapolis Royal	H		1984	20.0	C	20.00
Lingan	V(c)	150.0			I	
			1984	150.0	C	600.00
Fall River	H		1986	0.5	P	0.50
Nictaux	H		1986	6.8	P	6.80
New Thermal	V(c)		1991	300.0	P	300.00
Québec						
Beauharnois(net)	H	20.25			I	1 613.4
Delaney	H		1990	2 X 255	P	
			1991	5 X 255	P	
			1992	3 X 255	P	2 550.00
Gentilly 2	N	685.0			I	685.00
La Grande -						
LG-3	H	7 X 192			I	
			1984	2 x 192	C	2 304.00
Paugan (net)	H	6.88			I	208.86
Shawinigan 3 (net)	H	7.30			I	157.3
Trenche (net)	H	2.30			I	290.8

TABLE A7 (cont'd)

INSTALLED GENERATING CAPACITY EXPANSION IN CANADA BY STATION. MAJOR 1983 ADDITIONS AND PROJECTED 1984 - 2003

Province & Station	Type*	Additions in 1983 (MW)	Year	Additions Proposed (MW)	Status	Proposed plant capacity/ (MW)
Québec Cont'd						
LG-4	H		1984	7 X 293	C	
			1985	2 X 293	C	2 637.00
Manic 5	H		1992	2 X 247	C	
Various Locations	H		1993	2 X 247	C	2 280.00
			1993	100	P	
			1994	800	P	
	CI	3.90			I	
Ontario						
Atikokan	V(C)		1984	206	C	
Bruce B	N			2 X 781	C	
			1986	781	C	
			1987	781	C	
	TG	2 X 14			I	3 152.00
Darlington	N		1988	881	C	
			1989	881	C	
			1991	881	C	
			1992	881	C	
	TG		1985	4 X 26	P	3 628.00
Pickering B	N	516			I	
			1984	2 X 516	C	
			1985	516	C	2 064.00
St. Mary's	H	2 X 18			I	54.00
Manitoba						
Limestone	H		1992	2 X 127.5	P	
			1993	5 X 127.5	P	
			1994	3 X 127.5	P	1 275.00
Wuskwatim	H		1999	96	P	
			2000	3 X 96	P	384.00
Conawapa	H		2001	130	P	
			2002	4 X 130	P	
			2003	5 X 130	P	1 300.00

TABLE A7 (cont'd)

INSTALLED GENERATING CAPACITY EXPANSION IN CANADA BY STATION. MAJOR 1983 ADDITIONS AND PROJECTED 1984 - 2003

Province & Station	Type*	Additions in 1983 (MW)	Year	Additions Proposed (MW)	Status	Proposed plant capacity (MW)
Saskatchewan						
Nipawin	H		1985	84	C	
Poplar River	V(c)	300	1986	2 X 84	C	252.00
					I	600.00
Alberta						
Genesee	V(c)		1988	400	C	
Keephills	V(c)	400	1989	400	C	800.00
					I	
			1984	400	C	
			1991	400	P	
Sheerness	V(c)		1992	400	P	1 600.00
			1986	380	C	
Jasper	H		1987	380	C	760.00
Slave River	H		1986	5	P	6.40
			1995	2 X 153	P	-
			1995	3 X 151	P	-
			1996	6 X 151	P	-
New Steam	V(c)		1997	151	P	1 816.00
			1993	375	P	-
			1999	2 X 375	P	-
			2000	2 X 375	P	1 875.00

TABLE A7 (cont'd)

INSTALLED GENERATING CAPACITY EXPANSION IN CANADA BY STATION. MAJOR 1983 ADDITIONS AND PROJECTED 1984 - 2003

Province & Station	Type*	Additions in 1983 (MW)	Year	Additions Proposed (MW)	Status	Proposed plant capacity (MW)
British Columbia						
Keenleyside	H		1994	2 X 60	P	
			1995	1 X 60	P	210.00
Peace Site C	H		1998	3 X 150	P	
			1999	3 X 150	P	900.00
Revelstoke	H		1984	4 X 460.75	C	1 843.00
Murphy Creek	H		1995	2 X 55	P	
			1996	3 X 55	P	275.00
Falls River	H		1994	22	P	31.60
Yukon						
Whitehorse system	H		1984	20	C	39.39

Legend

H	Hydro
S(C)	Steam (Coal)
S(G)	Steam (Gas)
N	Nuclear
IC	Internal Combustion
GT	Gas Turbine
W	Wind
I	Installed
C	Under Construction
P	Planned

Electric Power in Canada 1984

Canada

Cover: Revelstoke Hydro Electric Project on the Columbia River B.C.

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Electric Power in Canada 1984

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THE ELECTRIC POWER INDUSTRY IN CANADA

Industry Structure

Electrical energy in Canada is supplied by Crown corporations, investor-owned utilities, and industrial establishments. In 1984, government-owned utilities produced about 83 per cent of total generated electricity, investor-owned utilities about 8 per cent, and industrial establishments the remaining 9 per cent. Over the past fifteen years the percentage of energy produced by industrial establishments has decreased, while that of the utilities has increased (see Table 1).

Industrial establishments generate energy mainly for their own use, although a few sell energy to municipal distribution systems or utilities. About 70 per cent of Canadian industrial establishments with generation facilities are found in Quebec and British Columbia, reflecting the concentration of forest product, mining, and aluminum smelting companies in those two provinces. Over 82 per cent of the electricity generated by industrial establishments is from hydroelectric sources, 9 per cent from natural gas, 4 per cent from oil, and the remainder from other fuels.

Greater public ownership of electric utilities has been the trend in Canada, as provincial governments have taken over most investor-owned electric utilities. However, investor-owned utilities are still a prominent feature of the Canadian industry. Electricity in Prince Edward Island is supplied by an investor-owned utility. In Alberta, two major investor-owned utilities supply about 88 per cent of the electricity consumed in the province and municipally-owned utilities supply most of the remainder. An investor-owned utility in Newfoundland distributes 85 per cent of the electricity used in that province. This utility generates about 15 per cent of its requirements and purchases the remainder mainly from the provincially-owned utility. In the Yukon and Northwest Territories, the federally-owned Northern Canada Power Commission generates and distributes most of the electricity supplied. Two investor-owned utilities supply most of the remainder.

In most provinces, the utilities are fully integrated, from the generation of electricity to its delivery and sale to end users. The principal exception is in Ontario, where about 70 per cent of total electricity supply is purchased from Ontario Hydro and distributed by some 350 municipal utilities.

Table 1. Energy production by utilities and industrial establishments, 1970-1984

Year	Utilities	Industrial Establishments
	(percentage)	
1970	84	16
1975	87	13
1977	88	12
1979	90	10
1981	90	10
1982	90	10
1983	90	10
1984	91	9

Source: Statistics Canada Publications 57-202, 57-001.

Unlike investor-owned utilities, government-owned utilities do not pay income tax. In order to equalize income tax treatment, 95 per cent of federal income taxes paid by investor-owned utilities are refunded to the province of origin under the Public Utilities Income Tax Transfer Act. In the province of Alberta, the tax refund

is returned to electricity consumers. In Prince Edward Island, a portion of the tax refund is returned to utility customers. In Newfoundland, the federal tax refund is retained as general revenues of the provincial government.

The electric power industry is a significant presence within the Canadian economy. As indicated in Table 2, 73 946 people were employed by the industry in 1984. Total assets were $82 billion and long-term debt was $60 billion. The industry's revenues exceeded $14 billion in 1984, 10 per cent of which came from export earnings. Ontario Hydro, Hydro-Québec, and British Columbia Hydro are the three largest electric utilities in Canada and rank first, second and fifth respectively in terms of assets among all Canadian companies. Canadian electricity production relative to that in other countries is shown in Table 3.

Electric Utilities and Their Regulation

Under the Canadian Constitution, primary responsibility for electricity generation, transmission, and distribution rests with the provinces. The only exceptions are with respect to international exports and nuclear power. The National Energy Board, a federally constituted body, regulates all electricity sales from Canada to the United States. The construction and operation of nuclear plants are regulated by another federal tribunal, the Atomic Energy Control Board.

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH).

NLPC is an investor-owned utility which is involved primarily in distribution. The company was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited, and Union Electric Light and Power Company. Through its predecessors, the company's service dates back to 1895.

NLH is a provincial Crown corporation concerned primarily with electricity generation. It was incorporated in 1975. NLH owns and operates Churchill Falls (Labrador) Corporation Limited (CFLCo). It is also the parent company for the Lower Churchill Development Corporation with 51 per cent ownership, in partnership with the Government of Canada which has a 49 per cent interest. In addition, NLH administers the activities of the Power Distribution District of Newfoundland and Labrador on behalf of the Province, and through CFLCo administers the activities of Twin Falls Power Corporation Limited. NLPC and NLH serve about 200 000 customers.

The two utilities are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the activities of NLPC. Since 1977, the Board also has had the authority under the Electric Power Control Act to regulate NLH's rates to electricity retailers. The Board has no jurisdiction, however, over rates charged to industrial customers served through NLH's distribution agencies. It makes recommendations to the Newfoundland cabinet regarding NLH's industrial rates. The provincial cabinet is the final regulatory authority.

Table 2. Electric utility assets, debt, revenue and employees, 1984

	($ millions)			
	Assets	Debt	Revenues	Employees
Newfoundland	2 142	1 485	470	2 132
Prince Edward Island	83	28	62	195
Nova Scotia	1 429	1 333	498	2 454
New Brunswick	2 800	2 100	834	2 485
Quebec	27 129	18 326	4 101	18 560
Ontario	27 301	21 506	4 212	29 613
Manitoba	2 806	2 213	506	3 593
Saskatchewan	1 657	1 904	424	3 148
Alberta	4 396	1 946	1 330	4 672
British Columbia	10 579	8 387	1 513	6 764
Yukon/Northwest Territories	273	231	90	330
Canada	81 495	59 560	14 040	73 946

Source: Electric Utilities' Annual Reports.

Table 3. Comparative data of electric utilities in the world's major industrial countries in 1982

	U.S.A.	U.S.S.R.	Japan	Canada	F.R. Germany	U.K.	France	Italy
Generating Capacity (GW)	650	254*	140	85	75	65*	70	39*
Energy Production (TWh)	2 241	1 259*	523	376	304	260*	237	156
Production Per Capita (KWh)	9 944	5 064	4 906	15 283	5 952	4 975*	4 893	3 251
Average Growth Rate of Electricity Production %:								
1972-1977	3.6	6.0	4.5	5.7	4.0	1.2	4.4	4.3
1977-1982	.9	3.5	1.7	3.7	1.8	0.0	5.6	1.9

* Indicates 1981 figures.

Source: Electric Power Industry in Japan 1983, Statistics Canada Publication 57-202.

Prince Edward Island

Maritime Electric Company Limited (MEC) is an investor-owned electric utility which has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully-integrated electric utility system providing for the generation, transmission, and distribution of electricity throughout the Island. MEC operates two oil-fired generating plants on the Island at Charlottetown and Borden, has a 10 per cent equity interest in New Brunswick Power's dual fuel coal/oil fired No. 2 unit located in Dalhousie, and leases the submarine cable interconnection to New Brunswick owned by the Province of Prince Edward Island. MEC serves about 44 100 customers on the Island. The Town of Summerside has its own distribution system and purchases power from MEC.

MEC is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province.

Nova Scotia

In 1972 the Nova Scotia Power Commission (NSPC) bought the shares of the investor-owned Nova Scotia Light and Power Company Limited and in 1973 was incorporated as the present Nova Scotia Power Corporation serving all of the province. NSPC generates most of its electricity from thermal energy, with more than half of the production coming from coal. The Corporation also maintains hydro-generation facilities and purchases power from New Brunswick. The largest portion of the total production of the province is derived from the Lingan Generating Station. In 1984, NSPC served over 341 000 customers.

Prior to 1976, the Nova Scotia government directly set rates and other policies for electric utilities in the province. Since that time, the Board of Commissioners of Public Utilities has taken over this duty and has full decision making power.

New Brunswick

Prior to 1918, more than twenty organizations in New Brunswick, both public and private, were in the business of generating and distributing electricity. In 1918, the government of the day passed an Order-in-Council setting up a Water Power Commission to determine the water power resources of the province. Acting on the recommendation of the Commission, the New Brunswick Electric Power Commission (NB Power) was established by an Act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership, to all areas of the province. Electricity is generated from a balance of nuclear, hydro, and thermal sources, and also makes purchases from Quebec. NB Power directly provides electricity for almost 236 000 customers and indirectly serves an additional 37 000 customers through sales to municipal utilities.

The electricity rates of NB Power are not subject to review by any regulatory or judicial authority. Under the provincial Electric Power Act, rates must be sufficient to cover all costs.

Quebec

Hydro-Québec was established by the Legislative Assembly in 1944. After its creation, Hydro-Québec acquired the assets of Montreal Light, Heat and Power Consolidated and Beauharnois Light, Heat and Power Company. In 1963, Hydro-Québec

acquired the remaining ten privately-owned power companies, including the Shawinigan Water and Power Company, Southern Power Company Limited, Québec Power Company and Gatineau Power Company. Several municipal-distribution and public lighting systems were also acquired, together with almost all the electricity cooperatives in Quebec.

Hydro-Québec has two wholly-owned, active subsidiaries: the Société d'Energie de la Baie James (SEBJ), which is carrying out the construction of Phase 1 of La Grande Complex, and Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects. Hydro-Québec is also a shareholder in Churchill Falls (Labrador) Corporation Limited (CFLCo), which operates the Churchill Falls power plant, and in Nouveler Inc., which promotes energy efficiency and alternative energy sources. Currently, Hydro-Québec serves about 2.6 million customers and is responsible for the generation, transmission and distribution of most of the electricity sold in Quebec, the remainder being produced by industrial establishments. Almost all of the electricity generated by Hydro-Québec is from hydro sources.

Rates are fixed by Hydro-Québec and are subject to the approval of the Legislative Assembly.

Ontario

Ontario Hydro is a Crown corporation, established in 1906, by the Provincial Legislature. It has broad powers to produce, buy, and deliver electric power throughout the province and currently operates under the Power Corporation Act. The main responsibility of Ontario Hydro is to provide power to municipal utilities, which in turn distribute power to their own customers. In addition, Ontario Hydro supplies more than one hundred major industrial users directly and about 777 000 rural retail customers in areas or communities not served by municipal utilities. Electricity is generated from a balance of thermal, nuclear, and hydro sources. In 1984, approximately 3.1 million customers were served by Ontario Hydro and the Municipal Utilities in the province.

Ontario Hydro executes its responsibilities with the authority of the Lieutenant Governor in Council. The Minister of Energy may call upon the Ontario Energy Board to review the corporation's rates or rate-making practices. The Board also conducts hearings on bulk power rate revisions, and makes recommendations which are generally accepted by Ontario Hydro.

Manitoba

Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the Manitoba Hydro Act. It distributes electricity to consumers throughout the province, except for the central portion of Winnipeg which is served by the city-owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1984, Manitoba Hydro served about 334 000 customers directly. Almost all of the electricity produced is derived from hydraulic sources.

Under the Manitoba Hydro Act, rates are set by Manitoba Hydro and reviewed by the Public Utilities Board. The Board provides advice to the provincial government, leaving the Lieutenant Governor in Council with final authority over pricing and other matters related to the supply of electricity.

Saskatchewan

The Saskatchewan Power Corporation (SPC) was established as a Crown corporation under the 1950 Power Corporation Act. It replaced the Saskatchewan Power Commission, created in 1929 to develop an integrated provincial electrical system. Under the Power Corporation Act, the mandate of the corporation includes the generation, transmission, and distribution of natural gas and electricity. The SPC also began operating the natural gas utility in 1952. At the end of 1984, the corporation was serving about 386 000 customers with electricity and 253 500 customers with natural gas. The bulk of the electricity produced is from thermal sources.

The Power Corporation Act authorizes the Saskatchewan Power Corporation to set rates for natural gas and electricity. These rates, however, are subject to review and approval by the Public Utilities Review Commission of Saskatchewan.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together they supply about 98 per cent of Alberta's electrical energy requirements.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. Over 74 per cent of the electric energy requirements of Alberta and over half of the population are supplied by the company. At the end of 1984, about 280 000 customers were served directly. Almost all of the electricity generated is from coal.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. Alberta Power supplied about 17 per cent of the total Alberta electricity requirements in 1984, serving about 140 000 customers. Almost all of the electricity generated is also from coal.

Edmonton Power is Alberta's second largest electric utility and the largest municipally-owned utility in terms of generating capacity in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. The utility produced slightly over 7 per cent of the electricity requirements of Alberta in 1984 and served more than 224 000 customers.

The utilities are regulated by the Energy Resources Conservation Board, with respect to the development of generation and transmission facilities. Hydro and thermal plant construction and operation require Board approval, with authorization from the Lieutenant Governor in Council. In addition, hydro construction requires statutory authorization.

Electricity rates are regulated by the Public Utilities Board. The three utilities sell energy at "pooling interfaces" to the Electrical Energy Marketing Agency (EEMA) at prices established by the Board based on their upstream costs. EEMA sells the electricity back to the utilities at an average price to reduce price disparities in the province. The Public Utilities Board also has jurisdiction over the consumer rates and service of investor-owned utilities. Edmonton Power is exempt from this control as it is a municipally-owned utility.

British Columbia

British Columbia Hydro and Power Authority (B.C. Hydro), incorporated in 1961, is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the area served by Cominco Limited and its subsidiary, West Kootenay Power and Light Company Limited. B.C. Hydro is the third largest electric utility in Canada and the largest distributor of natural gas in British Columbia. B.C. Hydro generates, transmits, and distributes electricity to more than one million customers in a service area which contains more than 90 per cent of the population of British Columbia. It also distributes natural gas in Greater Vancouver and in the Fraser Valley, and propane-air gas in Greater Victoria.

The British Columbia Utilities Commission (BCUC) has general supervision powers over B.C. Hydro. Jurisdiction extends to system expansion operation, financial transactions, and rate schedules. Cominco is exempted from this general regulation, subject to its compliance with several terms and conditions related to its pricing structure and use of facilities. New electricity exports require removal permits granted by the BCUC, after authorization by the Lieutenant Governor in Council.

Yukon and Northwest Territories

The Northern Canada Power Commission (NCPC) is a federal Crown corporation, created in 1956, under authority of the Northern Canada Power Commission Act. It is concerned with the planning, construction and management of utilities on a commercial basis. The Commission is the principal producer of electricity north of 60° and operates the main transmission networks in the north. Currently the NCPC serves more than 12 000 customers.

Under the Northern Canada Power Commission Act (NCPCA), the Commission is to be self-sustaining within the rate zones of the Yukon and Northwest Territories. To ensure this, rates charged by utilities must provide sufficient revenue to cover capital and operating costs of the Commission. The Commission, although under no legal obligation to do so, generally abides by the recommendations of the Yukon and Northwest Territories Public Utilities Boards provided that the recommendations do not conflict with the requirements of the NCPCA.

DOMESTIC ELECTRICITY CONSUMPTION

Electricity Consumption in 1984

Canada's electricity demand grew 7.1 per cent in 1984, the highest annual increase since 1976. This increase can be attributed primarily to economic growth. Real Gross Domestic Product grew 4.7 per cent in 1984, also the highest annual increase since 1976. A move towards electric heating and away from oil also contributed to the growth in electricity consumption. Over the period October 1980 to December 1984, approximately 900 000 households have been converted from oil to alternative energy sources. The largest share of these conversions was from oil to electricity, representing 41 per cent of the total. A colder winter in 1984 relative to 1983 also affected electricity demand favorably.

Because of the strong increase in electricity demand, the electricity factor in the Canadian economy in 1984 continued to increase. The quantity of electricity consumed, expressed in kilowatt-hours per dollar of real GDP (1971$), was 3.09 in 1984, up from 3.02 in 1983, 2.65 in 1975, and 2.58 in 1970.

Table 4 presents the 1984 growth rates in electricity demand by province and by major utility. Growth rates vary considerably by province from a high of 12.3 per cent for New Brunswick to a low of 1.9 per cent for British Columbia. Of the major utilities, Hydro-Québec experienced the largest growth rate, at 12.7 per cent, followed by the New Brunswick Power Commission and Saskatchewan Power Corporation, with increases of 12.2 per cent and 10.1 per cent respectively.

Table 4. Percentage growth in electricity demand, 1984

	Province	Major Utilities
Newfoundland	5.7	4.8
Prince Edward Island	2.0	2.0
Nova Scotia	7.0	6.7
New Brunswick	12.3	12.2
Quebec	10.6	12.7
Ontario	5.5	5.8
Manitoba	2.9	4.6
Saskatchewan	10.1	10.1
Alberta	6.9	5.9
British Columbia	1.9	5.0
Yukon/NWT	9.5	7.6
Canada	7.1	8.4

Source: Energy, Mines and Resources Canada.

Electricity demand by sector, for the period 1979-84 is reported in Table 5. The industrial sector consumes the largest share of electricity. In 1984, this sector accounted for 50 per cent of total consumption, followed by the residential sector with 28 per cent, and the commercial sector with 22 per cent.

Forecast Demand

Forecasting electricity demand has become a more difficult task during the past ten years or so as a result of the economic dislocations caused by rapidly rising energy prices. The effects were felt on a global scale and major adjustments were made in the amounts and types of energy used. The decline in the international price of oil in the past couple of years has added to the uncertainty. Adjustments in energy consumption patterns continue to make economic forecasting difficult.

Table 5. Total electricity demand in Canada by sector, 1979-1984

	1979		1980		1981		1982		1983		1984	
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%	GWh	%
Residential and Farm	87 638	27	92 669	27	95 048	28	99 248	29	101 101	28	107 945	28
Commercial	72 384	22	73 450	22	75 681	22	77 770	22	80 753	22	84 814	22
Industrial	163 443	51	173 949	51	175 526	50	168 421	49	177 910	50	192 757	50
Total	323 465	100	340 068	100	346 255	100	345 439	100	359 764	100	385 515	100

Source: Statistics Canada Publication 57-202, 1979-1983.
Data for 1984 is preliminary.

FIGURE 1

HISTORICAL RELATIONSHIP BETWEEN PER CAPITA ELECTRICITY DEMAND AND PER CAPITA GROSS DOMESTIC PRODUCT

1960-1984

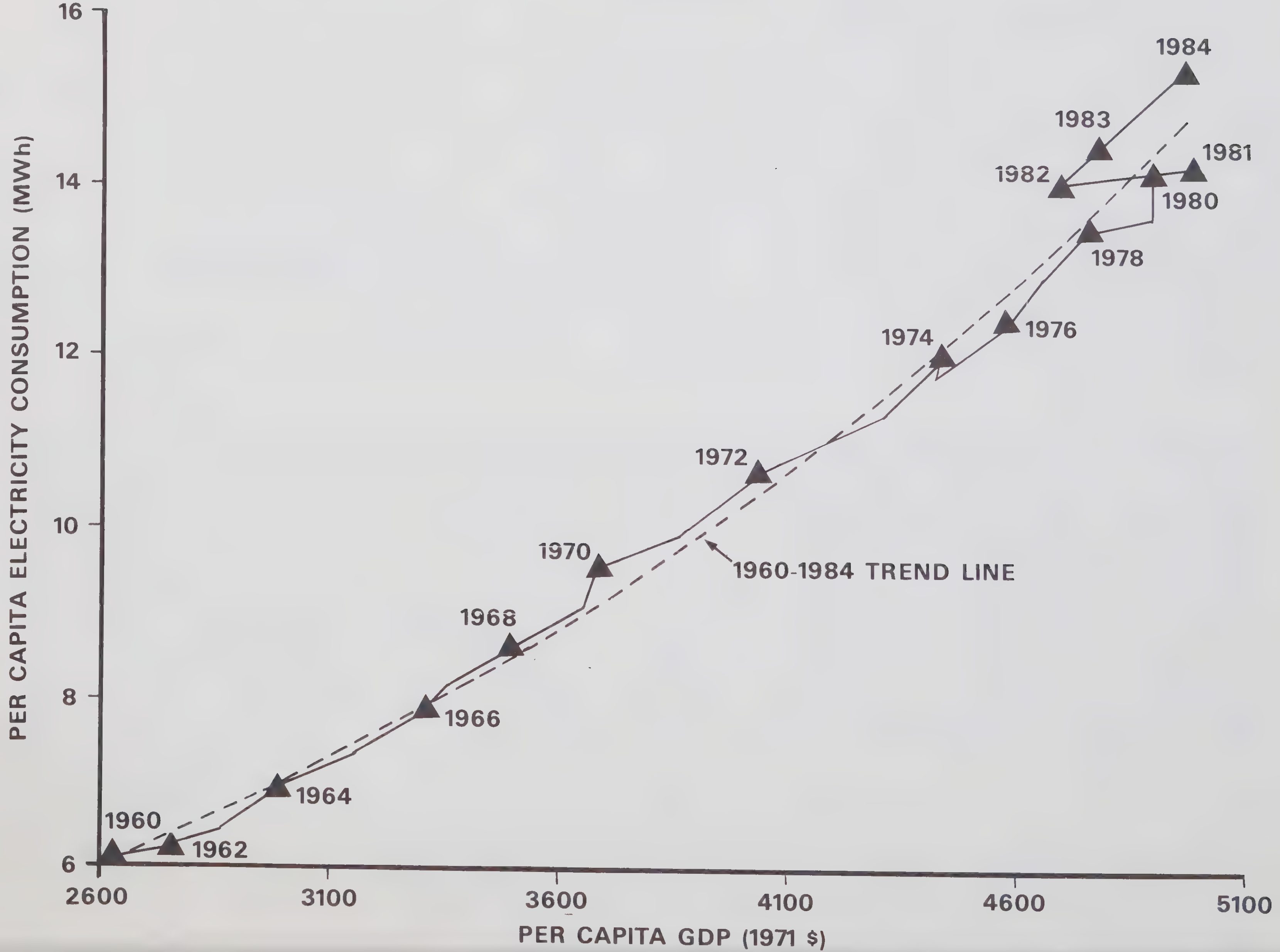


Figure 1 shows the close historical relationship between per capita economic performance, as measured by Gross Domestic Product (GDP), and per capita electricity demand.

Table 6 presents the growth, over the period 1960-1984, of real GDP (i.e. GDP net taking account of inflation), population, primary energy demand (i.e. the total energy available from the energy sources in their original state), and electrical energy demand. Table 6 also presents the forecasts prepared by the Department of Energy, Mines and Resources (EMR), for each of these variables for the period 1984-2000.

Since economic growth and population growth over the next sixteen years are expected to be significantly lower than that of the previous twenty-five year period, electricity growth is also expected to be lower. However, the forecasts presented in Table 6 also indicate an increasing role for electrical energy in Canada. The percentage of primary energy supplied in the form of electricity is expected to increase from 42 per cent in 1984 to about 44 per cent in 1990 and 46 per cent in the year 2000.

Table 6. Historical and forecast annual growth rates

	(per cent)		
	1960-84	1973-84	1984-2000
Real GDP	4.2	2.5	3.0
Population	1.4	1.2	0.7
Primary Energy	3.6	1.4	2.5
Electrical Energy	5.4	3.7	2.9

Source: Energy, Mines and Resources Canada.

The long (5-10 years) lead times required to bring new generation facilities into service requires forecasts of future demand. Thus despite the inherent difficulties, forecasts must be made. Forecasts of the growth in electricity demand, prepared by the major utilities and provided to EMR in January 1985, are summarized in Table 7. The extent of the changed perception of future demand is illustrated by the forecasts provided by the utilities last year, shown in brackets in Table 7. With the exceptions of Prince Edward Island, Nova Scotia, and New Brunswick, all electric utilities reduced their forecast demand growth over the period 1984-2000 from the forecasts provided in January 1984.

Table 7. Utility forecasts of electricity demand (per cent)

	1984-1990	1990-2000	1984-2000
Nfld.	2.8 (4.0)	2.9 (4.3)	2.8 (4.2)
P.E.I.	3.9 (1.0)	2.7 (1.0)	3.2 (1.0)
N.S.	4.3 (3.8)	3.7 (3.7)	3.9 (3.7)
N.B.	3.1 (3.2)	2.3 (2.2)	2.6 (2.6)
Que.	2.6 (2.9)	2.0 (2.9)	2.2 (3.1)
Ont.	2.2 (2.8)	2.3 (2.2)	2.2 (2.5)
Man.	2.5 (3.3)	2.5 (2.8)	2.5 (3.0)
Sask.	2.2 (2.9)	2.2 (2.5)	2.2 (2.6)
Alta.	4.3 (4.5)	3.6 (4.1)	3.9 (4.2)
B.C.	2.1 (2.7)	1.4 (2.5)	1.7 (2.6)
N.W.T/ Y.T.	1.0 (3.7)	0.5 (1.5)	0.7 (2.3)
Canada	2.6 (3.0)	2.2 (2.6)	2.4 (2.8)

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

The significantly reduced electricity demand forecasts illustrate how difficult it is to forecast electricity demand with a high degree of confidence. Rather than single value

forecasts, most utilities are now considering a range of demand forecasts with an assignment of statistical probability to each. As well, they are adopting an approach to planning which emphasizes flexibility. Rather than plan generation capacity to meet whatever demand develops, they are taking steps to alter peak demand requirements by means of direct load management, while simultaneously ensuring that generating capacity is sufficient to meet demand under reasonable assumptions regarding future growth.

Figure 2 illustrates various forecasts for electricity demand. Included on the bar chart for comparison are the National Energy Board 1984 base case, the latest forecast derived from EMR's Interfuel Substitution Demand Model, and the forecast developed by the EMR Electrical Energy Branch on the basis of projections provided by the major utilities.

Peak Demand

Peak demand in Canada grew by 3.6 per cent in 1984, up from 67 000 MW in 1983 to about 69 000 MW in 1984. Based on the electric utilities' projections, peak demand is expected to increase annually by 2.1 per cent, to 97 000 MW by the year 2000. Table 8 reports the forecast peak demand growth rates for all provinces and territories, as projected by the major electric utilities for the period 1984-2000.

Load Factor

As was pointed out earlier, energy demand grew faster than peak demand in 1984. The growth rate was 7.1 per cent for energy compared with 3.6 per cent for peak; load factor for Canada as a whole, therefore, increased by 3.4 per cent, from 61.6 per cent in 1983 to 63.7 per cent in 1984. Load factors for each province and Canada during the period 1984-2000 are reported in Table 9.

Table 8. Peak demand growth rates (per cent)

	1984-1990	1990-2000	1984-2000
Nfld.	2.3	3.2	2.9
P.E.I.	3.2	2.7	2.9
N.S.	4.3	3.8	4.0
N.B.	4.7	2.3	2.9
Que.	-0.1	2.2	1.3
Ont.	2.3	2.2	2.3
Man.	3.6	2.5	2.9
Sask.	2.7	2.1	2.3
Alta.	4.3	4.0	4.1
B.C.	1.7	1.6	1.6
N.W.T./ Y.T.	1.1	0.5	0.7
Canada	1.7	2.4	2.1

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

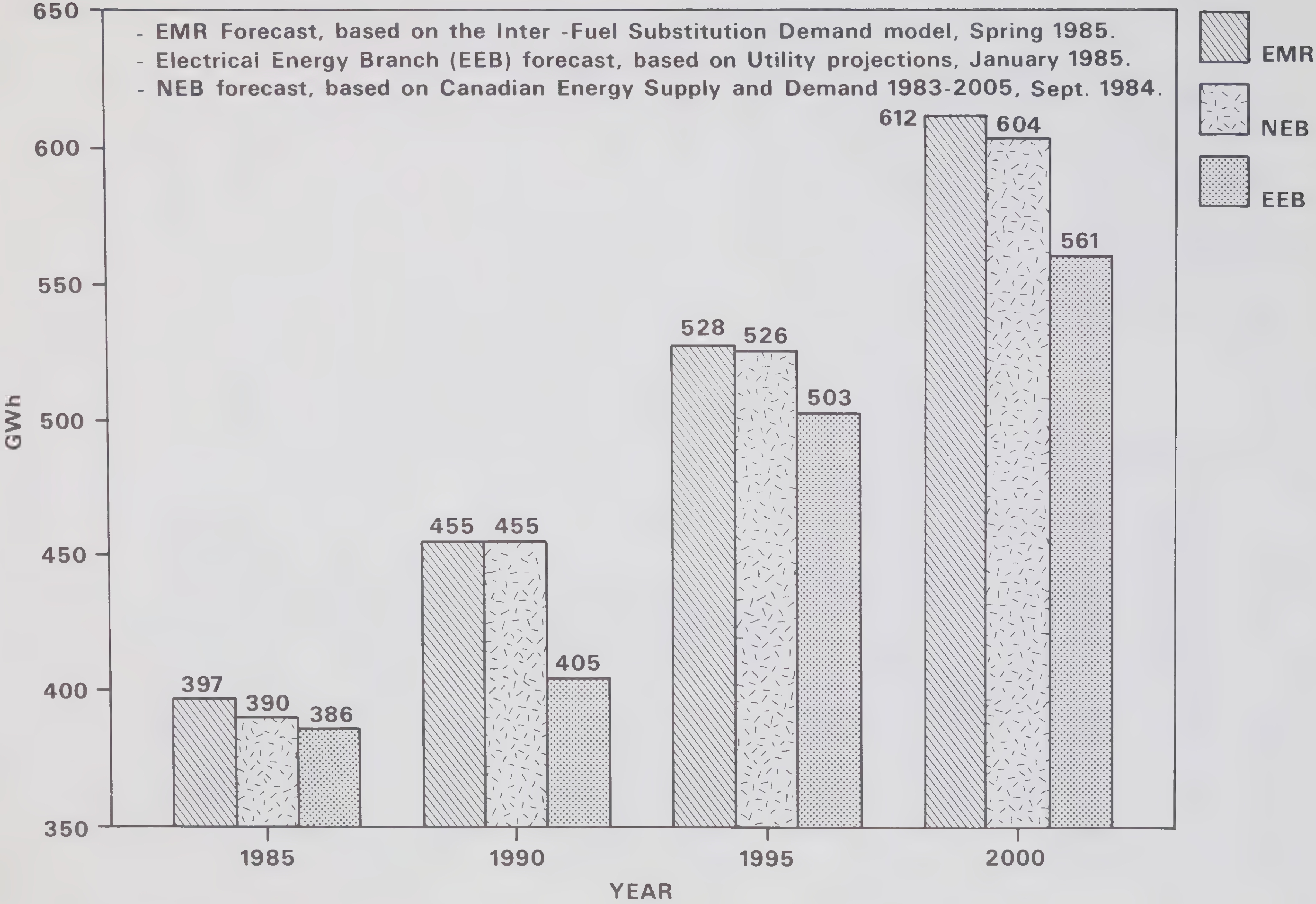
Table 9. Load Factor in Canada (per cent)

	1984	1990	2000
Nfld.	53.6	55.0	53.2
P.E.I.	57.7	60.4	60.5
N.S.	62.9	62.8	62.2
N.B.	62.5	59.2	59.2
Que.	61.4	72.4	71.0
Ont.	67.3	66.9	67.1
Man.	60.0	56.2	56.1
Sask.	61.2	59.4	59.8
Alta.	70.3	70.2	67.4
B.C.	62.9	64.5	63.1
N.W.T./ Y.T.	55.0	54.9	54.9
Canada	63.7	67.2	66.3

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

FIGURE 2

ELECTRICAL ENERGY FORECASTS



GENERATING CAPACITY

New Additions

Total generating capacity increased by 6 250 MW in 1984 to 95 530 MW at year end, a 6.7 per cent increase over 1983. Hydro capacity additions totaled 3 857 MW, nuclear 1 816 MW, and conventional thermal 577 MW, representing 62 per cent, 29 per cent, and 9 per cent of the total additions respectively. A summary of the major additions is presented in Table 10.

Total installed capacity by principal fuel type by province for 1984 is illustrated in Figure 3. Installed capacity by region and installed capacity by energy source for Canada, are shown in Figures 4a and 4b. Figure 5 presents a graph indicating historical installed capacity for Canada during the period 1960-1984. Although the market share of hydro has decreased since 1960, it is still the most important electric power source in Canada. In 1984, hydro accounted for 59 per cent of total installed generating capacity.

Table 10. Major changes to installed generating capacity during 1984

	Project	Plant Type	No. of Units	Capacity MW
Additions				
Nova Scotia	Lingan	Steam (coal)	1	150
	Annapolis Royal	Hydro	1	20
Quebec	La Grande 3	Hydro	2	384
	La Grande 4	Hydro	7	2051
Ontario	Bruce B	Nuclear	1	784
		Gas Turbine	2	33
	Pickering B	Nuclear	2	1032
Alberta	Keephills	Steam (coal)	1	394
British Columbia	Revelstoke	Hydro	3	1382
Yukon	Whitehorse #4	Hydro	1	20

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

FIGURE 3

INSTALLED CAPACITY BY PRINCIPAL FUEL TYPE
1984% OF PROVINCIAL TOTAL

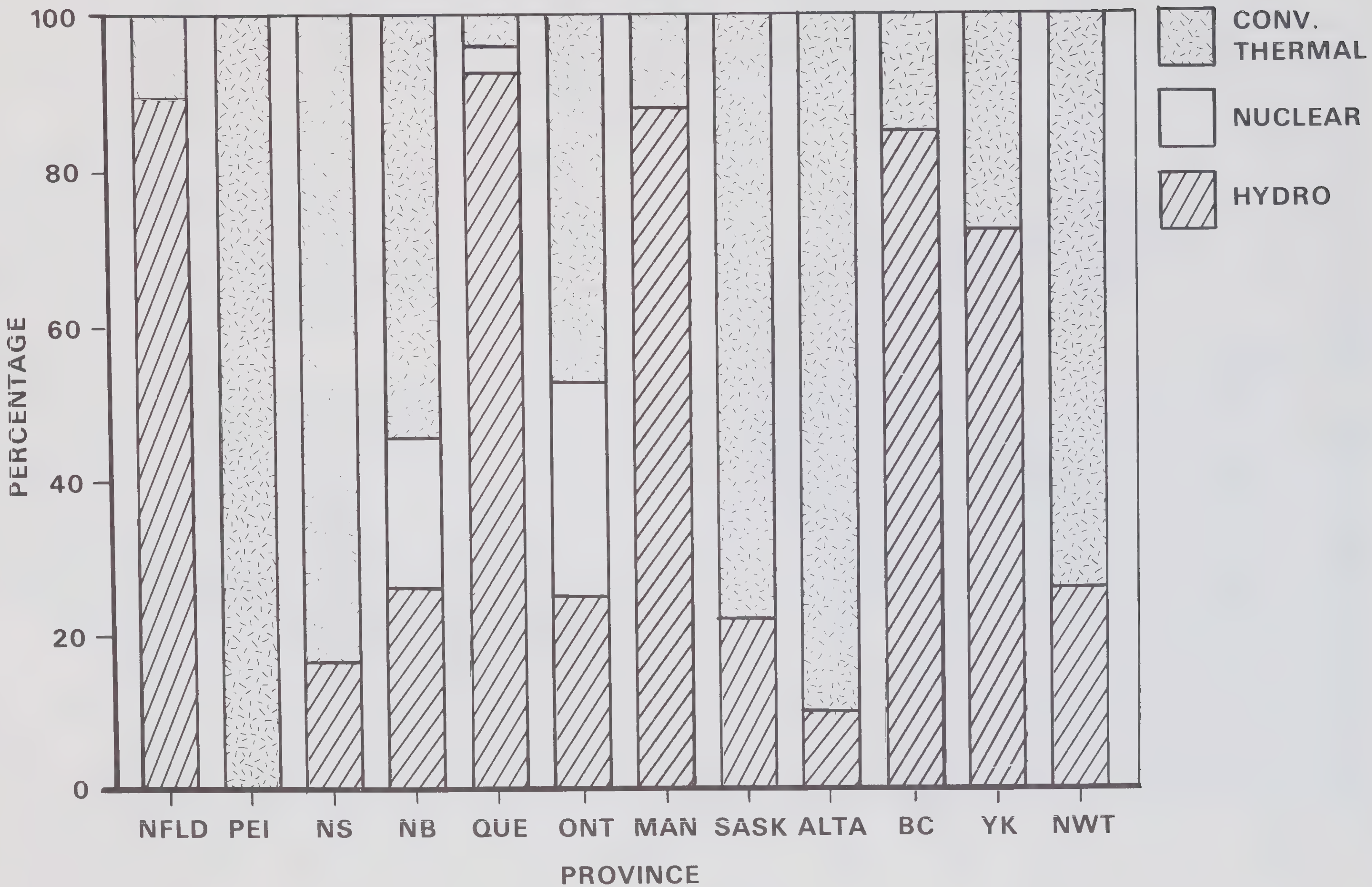


Figure 4a

CAPACITY BY REGION 1984

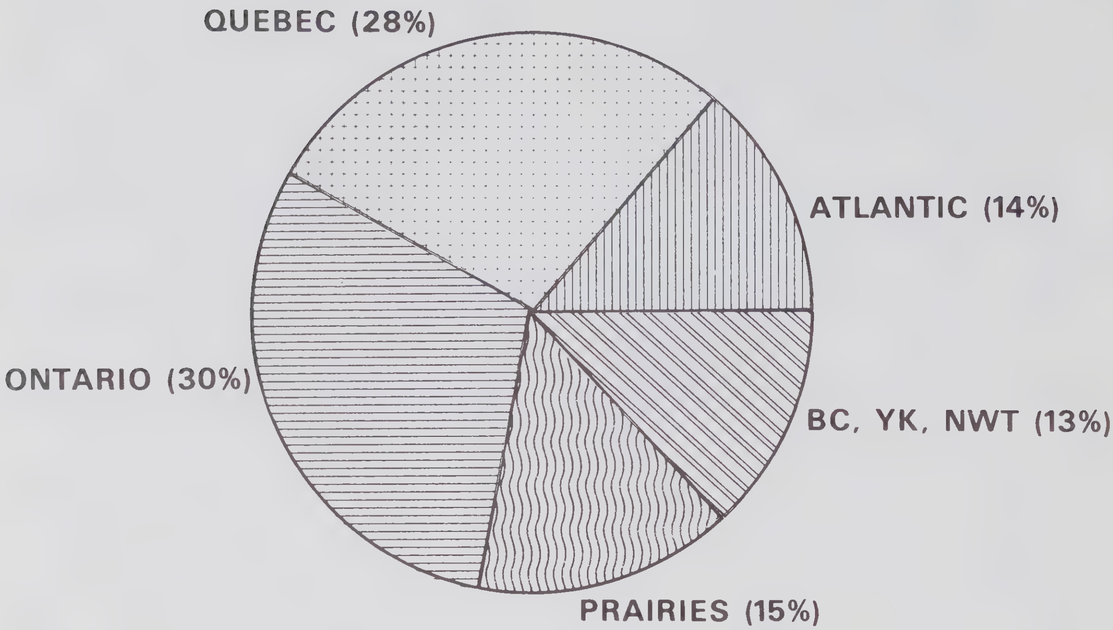


Figure 4b

CAPACITY BY ENERGY SOURCE 1984

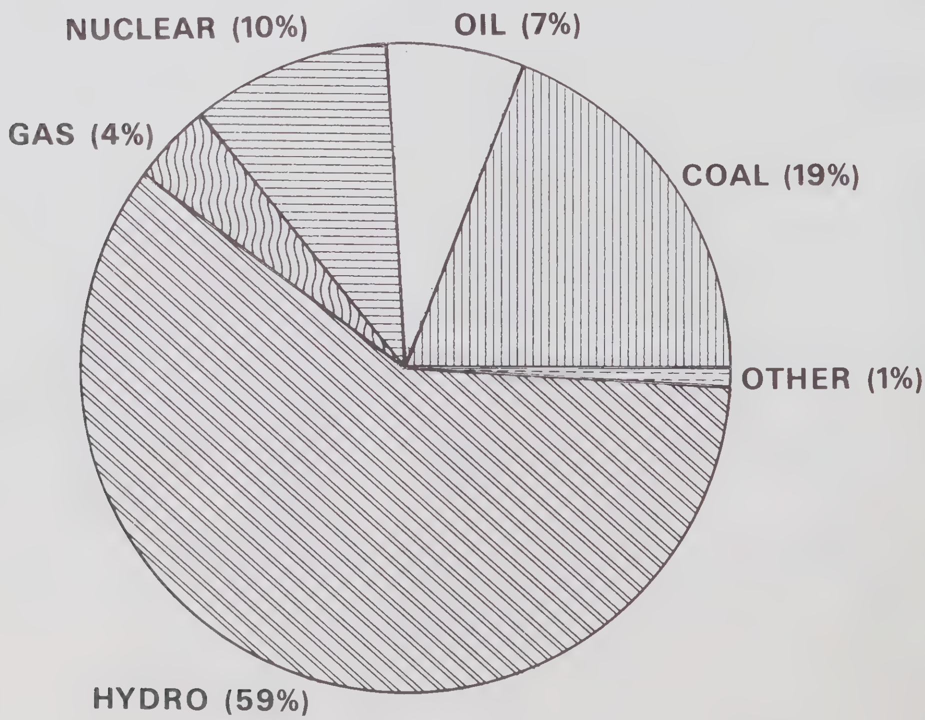
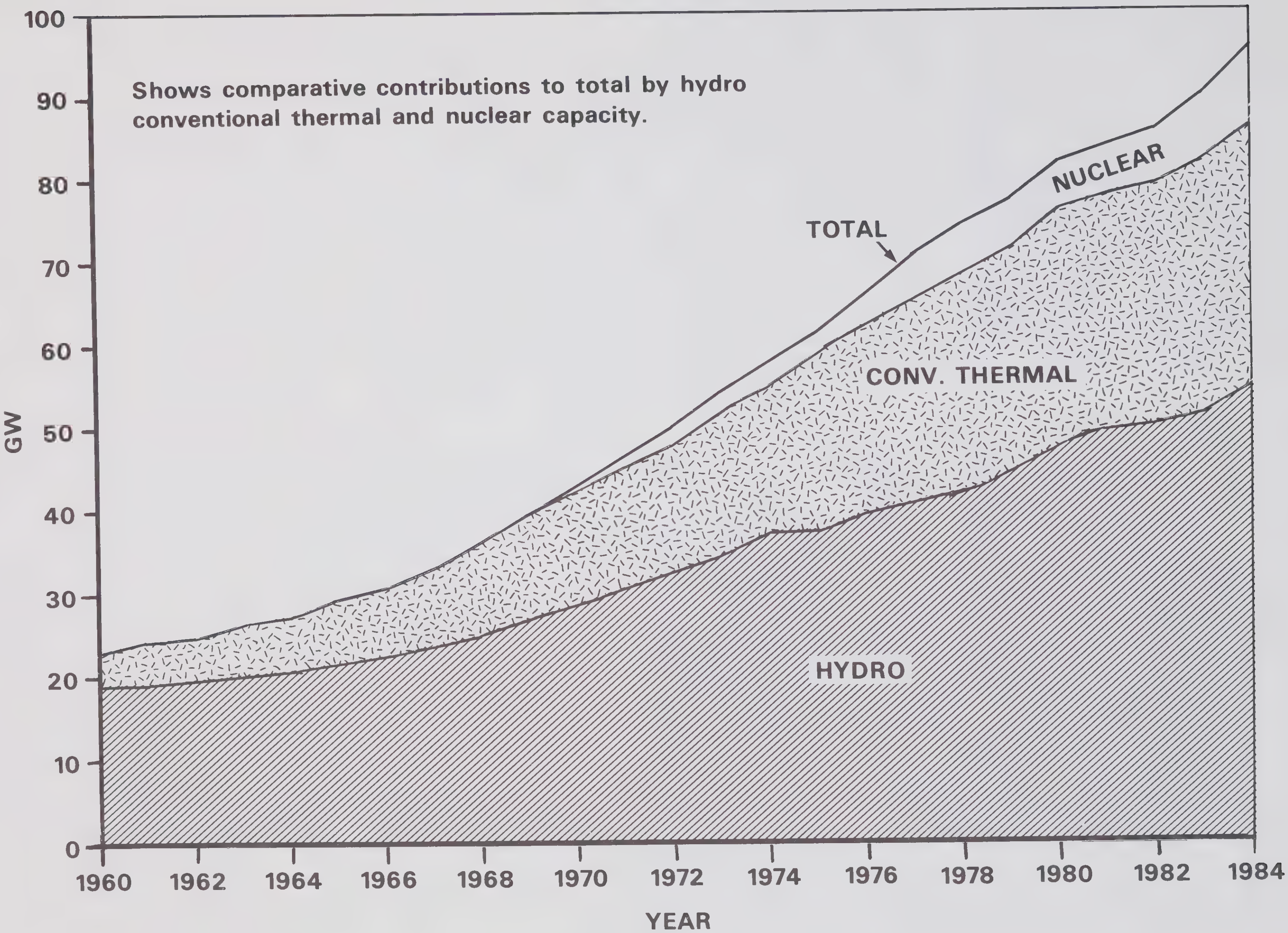


FIGURE 5

HISTORICAL INSTALLED CAPACITY, 1960-1984



Forecasts of Generating Capacity

To meet the forecast growth in electricity demand, total installed generating capacity in Canada is expected to increase at an average annual rate of 1.5 per cent, from 95 000 MW in 1985 to 118 000 MW by the end of the century. The fact that this level of growth is significantly less than energy and peak demand growth, reflects the current excess capacity situation in certain provinces, notably Nova Scotia, New Brunswick, Quebec, Ontario, Manitoba, and British Columbia. Capacity, by energy source, is displayed in Table 11.

The largest share of total Canadian capacity over the next 15 years will continue to be hydro, with its 57 per cent share of total capacity remaining relatively stable through the period. Nuclear installed capacity will increase considerably between 1985 and 1990, but will experience slow growth in the 1990s. Nuclear generating capacity, as a share of total capacity, is expected to increase from 10 per cent in 1985 to 13 per cent in 1990, and to stabilize thereafter.

While coal-fired capacity is expected to increase moderately over the forecast period, its capacity share is expected to be fairly stable at about 19 per cent of total capacity. Natural gas capacity will decrease gradually, from 4 per cent in 1985 to 3 per cent by 2000.

Oil-fired capacity is expected to increase slightly over the period, although its share of total capacity is expected to remain stable at about 7 per cent. Oil will be used primarily for peaking purposes; coal, nuclear, and hydro will continue to account for most of the electricity generated in Canada. These latter sources accounted for 88 per cent of total capacity in 1984, and this percentage is expected to increase slightly by the year 2000.

Table 11. Forecasts of installed generating capacity by principal fuel type - Canada

	Installed Generating Capacity (MW)							Percentage of Installed Capacity						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
1985	17.9	7.3	3.6	10.0	55.7	0.5	95.0	19	8	4	10	58	1	100
1990	18.7	7.3	3.4	13.6	58.6	0.6	102.2	18	7	4	13	57	1	100
1995	20.4	7.2	3.7	15.3	61.8	0.8	109.2	19	7	3	14	56	1	100
2000	22.7	8.1	3.4	15.3	67.1	1.0	117.6	19	7	3	13	57	1	100

Source: Energy, Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

RESERVE MARGINS

There have been two distinct periods in the growth of electricity demand in Canada since World War II. From 1947 to 1974 there was a period of rapid growth, with an average annual increase of 6.8 per cent. Following the oil crisis of 1973-1974, electricity growth slowed to an average rate of 3.4 per cent for the period 1975-1984. During the latter period, electricity consumption actually declined in 1975 and again in 1982.

This shift, from a long period of sustained rapid growth to one of slower growth, resulted in excess generating capacity. In the early 1970s, the construction of new generating stations was initiated on the basis of expectations of continuing rapid growth in electricity demand. As the growth in demand slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to requirements.

Present Reserve Margin

For an electrical system, the per cent reserve margin is defined as the excess of installed generating capacity over annual peak load expressed as a per centage of annual peak load. Table 12 presents the reserve margin in all ten provinces. The highest reserve is in New Brunswick with 57 per cent, followed by Nova Scotia with 55 per cent, British Columbia with 47 per cent, and Ontario with 41 per cent. No new generating plants are now under construction in New Brunswick, Nova Scotia, and British Columbia. Other than the four units at the Darlington nuclear facility, which will be completed in 1992, no additional units are presently committed in Ontario.

Capacity Reserve Requirements

Normal practice in an electrical system is that a certain proportion of installed capacity is designated to allow for scheduled maintenance, planned outage, and unexpected peak demand. This proportion is usually called the capacity reserve requirement. It varies from utility to utility depending on the installed capacity mix of the electrical system. Table 12 reports the capacity reserve requirement in each province. Ontario Hydro has the largest capacity reserve while Hydro-Québec has the lowest.

Surplus Generating Capacity

Surplus generating capacity is defined as the reserve margin less the reserve capacity requirement. Table 11 indicates surplus generating capacity by province for 1984. With the exception of Prince Edward Island, all provinces had surplus capacity. In New Brunswick, Nova Scotia, and British Columbia, the surplus exceeded 30 per cent. The weighted surplus for Canada as a whole was 21 per cent.

Table 12. Surplus of installed generating capacity in 1984

	Reserve Margin (1)	Capacity Reserve Requirement (2)	Net Surplus (3) = (1) - (2)
Newfoundland	39	12	27
Prince Edward Island	16	20	-4
Nova Scotia	55	20	35
New Brunswick	57	20	37
Quebec	28	10	18
Ontario	41	25	16
Manitoba	37	15	22
Saskatchewan	18	15	3
Alberta	38	22	16
British Columbia	47	15	32
Canada	35	14	21

Source: Energy, Mines and Resources Canada.

ENERGY SUPPLY

Energy Generation

Electricity generation increased 7.4 per cent in 1984 to 425 TWh. Of this, 386 TWh was for use in Canada and the remainder was exported. The sources of generation were as follows:

Source of electricity production

Generation Type	% of 1984 Generation	% Increase from 1983
Hydro	66.7	7.7
Thermal	21.7	6.7
Nuclear	11.6	6.6

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

The increased hydro generation was mainly attributable to new production from James Bay (12 000 GWh) and Revelstoke (10 800 GWh), and to increased production from Churchill Falls (5000 GWh). Electricity production from fossil fuels increased by 6.7 per cent in 1984 over 1983. The fossil fuel share of total electricity production was 22 per cent, the same as the previous year. The production of electricity from coal increased by 11 per cent, while generation from oil and gas decreased by 3 per cent and 34 per cent respectively. Total nuclear production increased by 6.6 per cent.

Energy production by fuel type and province is shown in Figures 6 and 7. The major increases in coal-fired production were in Nova Scotia (28 per cent), Saskatchewan (22 per cent), and Alberta (17 per cent). In New Brunswick, coal production declined by 45 per cent. Natural gas is used for electricity production primarily in Alberta, British Columbia, and Ontario. Production declined by 57 per cent in Alberta, 13 per cent in Ontario, and 6 per cent in British Columbia.

Oil-fired production declined in Newfoundland as a result of increased hydro generation and in Nova Scotia as a result of displacement by coal-fired production. New Brunswick increased oil-fired production because of its export commitment. It is estimated that about 80 per cent of electricity generated from oil was exported to the U.S.

Nuclear generation was 11.6 per cent of the total in 1984. In Quebec, the Gentilly II station increased its generation substantially from 1990 GWh in 1983 to 3422 GWh in 1984. In Ontario, three new nuclear units were put in service, and the remaining increase for the year came from increased production in New Brunswick.

FIGURE 6

ENERGY GENERATION BY PRINCIPAL FUEL TYPE

1984 % OF PROVINCIAL TOTAL

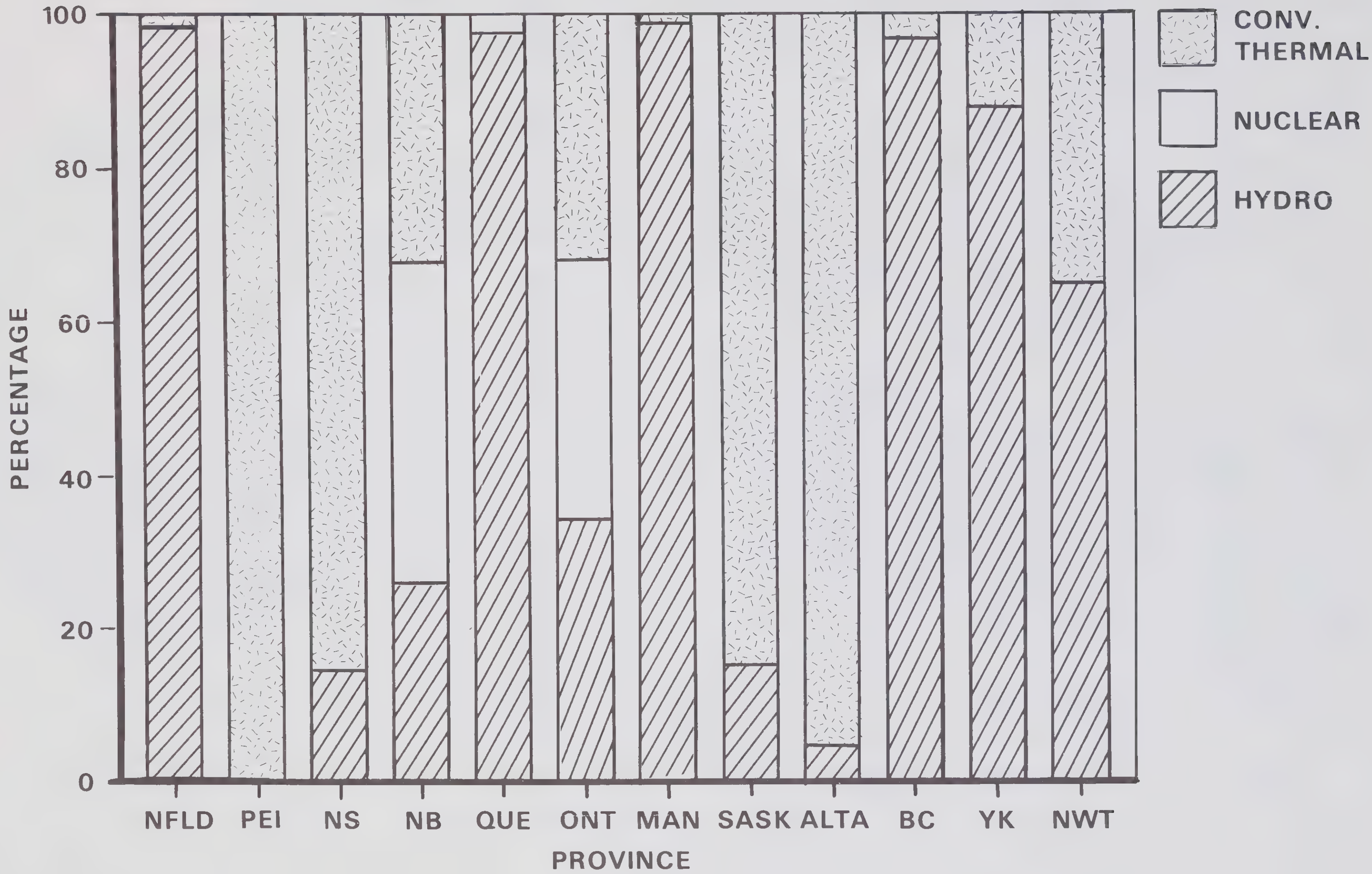


Figure 7a

PRODUCTION BY REGION 1984

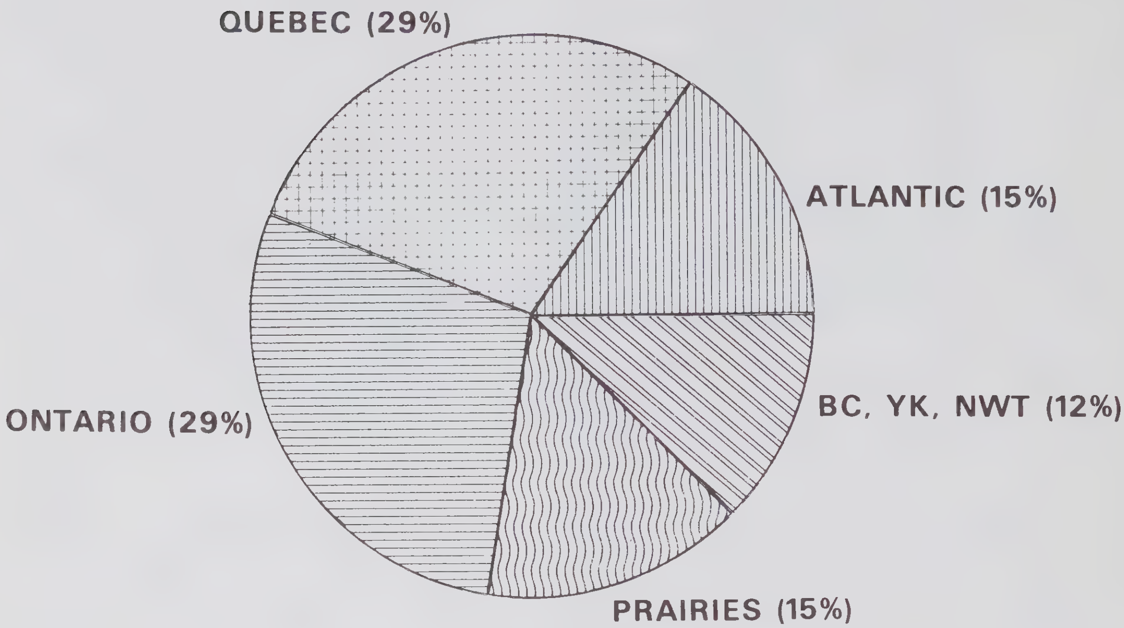
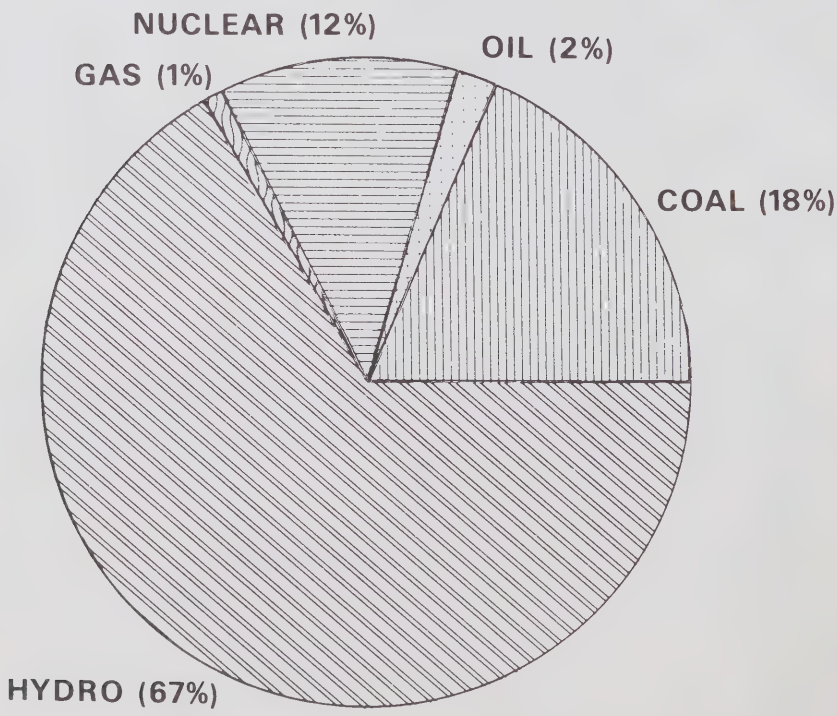


Figure 7b

PRODUCTION BY ENERGY SOURCE 1984



Forecast of Energy Generation

Utility forecasts of electricity generation, by principal fuel type for Canada, are presented in Table 13. The data suggest that hydro-based generation will continue to be the most important source of electric energy in Canada, although its share of total electricity production will decline slightly, from about 67 per cent in 1985, to about 62 per cent in 2000. Coal-fired production is expected to decrease, in both quantity and market share, between 1985 and 1990, and then steadily increase to 16 per cent of total electricity generation by the year 2000. Ontario Hydro is the main factor in this decrease, because it plans to reduce its coal-fired generation from 37 TWh in 1984, to only 13 TWh by 1990. This substantial reduction will be offset by increasing nuclear production from the Darlington nuclear stations.

Oil-fired stations will continue to be used as peaking capacity and to serve energy demand in remote locations. Beyond 1990, the use of oil in electricity generation is expected to increase with the overall increase in demand. By the year 2000, the share of electricity generated from oil is expected to reach 2 per cent of total electricity generation. Natural gas will continue to be used sparingly, accounting for only about 1 per cent of total electricity generation throughout the period.

Nuclear generation is forecast to increase at an average annual rate of 4.9 per cent between 1985 and the year 2000. Its share of electricity generation is expected to increase from 14 per cent to about 18 per cent over the same period.

Table 13. Forecasts of energy generation by fuel type - Canada

	Energy Generation (TWh)							Percentage of Generation						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
1985	71.4	6.7	4.9	61.0	298.1	2.3	444.4	16	1	1	14	67	1	100
1990	64.9	6.8	4.7	99.2	320.2	3.1	498.9	13	1	1	20	64	1	100
1995	74.3	8.2	6.9	111.7	339.9	4.0	545.3	14	1	1	21	62	1	100
2000	100.1	9.4	6.3	106.1	370.2	6.0	598.1	16	2	1	18	62	1	100

Source: Energy, Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

ELECTRICITY TRADE

International Trade

Canada's international electricity trade for the period 1980-1984 is summarized in Table 14. Net electricity exports to the United States increased by 10 per cent in 1984, as did net revenue. Total exports were 41 435 GWh, while imports were 2343 GWh. About 71 per cent of the electricity exported in 1984 was interruptible; that is, it was available only when surplus to the selling utility's needs. Hydro-generated electricity continued to account for more than half of the total exported.

The provincial sources of exports and the average revenue received since 1982 are shown in Table 15. Three provinces - New Brunswick, Quebec, and British Columbia - showed increases during 1984.

British Columbia's exports increased dramatically during the third quarter of 1984, with increased demand for Canadian electricity by the City of Los Angeles, but dropped in the last quarter after the implementation of a new intertie access policy by Bonneville Power Administration (BPA) in the United States. BPA owns and operates the transmission system from the U.S. Northwest, to the California/Oregon border, and the new intertie policy gives Northwestern U.S. utilities preference over Canadian utilities. The increases in Quebec resulted from greater interruptible sales arising from new contracts with the Power Authority of the State of New York. Ontario Hydro lost some nuclear generation in 1984 because of outages of certain nuclear units. This loss of generation, along with increased competition in the Michigan and New York markets, contributed to a decline in Ontario Hydro's interruptible sales. Exports from Manitoba and Saskatchewan also declined in 1984.

The average revenue received from electricity exports during 1984 varied significantly from province to province. New Brunswick received the highest average revenue, $61.5 per megawatt hour, while British Columbia received the lowest, $15.3 per megawatt hour. The factors which affect the value of electricity exports include whether the electricity is exported on a firm or interruptible basis, the generating costs of the exporting utility, the generating costs avoided by the importing utility, and the cost of transmission. Interruptible electricity supply is less valuable to the importing utility since it must maintain standby generating capacity. The generating costs incurred by the exporter and avoided by the importer vary according to the type of electricity generation. For base load generation in both Canada and the United States, oil-fired generating plants tend to be the most costly and hydro the least costly.

Table 16 presents the proportion of firm and interruptible electricity exports for each province. While firm exports accounted for just under 30 per cent of total Canadian electricity exports in 1984, the proportion of firm to total exports ranged from 8 per cent in British Columbia to 100 per cent in Saskatchewan.

Table 17 presents the energy sources of electricity exported during 1984. Exports from Quebec, Manitoba, and British Columbia were generated almost entirely from hydroelectric stations, while exports from Ontario were generated primarily from thermal stations using imported coal. In New Brunswick, the generation sources were nuclear, oil, and coal.

The export market areas, and the types of electricity generation displaced by Canadian exports, are presented in Table 18. In all markets, Canadian exports displaced electricity which would have otherwise been generated from fossil fuels.

Table 14. International electricity trade, 1980-1984

	1980	1981	1982	1983	1984
			(GWh)		
Exports[a]	28 229	34 730	32 986	36 907	37 572
Imports[a]	169	466	268	211	291
Net exports	28 060	34 264	32 718	36 686	37 281
Type of exports[b]					
Firm	7 236	5 008	5 829	10 218	10 852
Interruptible	20 993	29 722	27 157	26 689	26 720
Total	28 229	34 730	32 986	36 907	37 572
Generation source for exports:[c]					
Hydro	12 336	19 948	18 574	19 237	20 555
Imported coal	10 599	10 901	10 315	11 704	10 582
Imported oil	2 867	1 940	1 959	1 201	1 552
Domestic coal/oil	593	665	502	519	711
Nuclear	30	42	96	1 856	1 911
Other[d]	1 804	1 234	1 540	2 390	1 352
Total	28 229	34 730	32 986	36 907	36 663
Revenue/Cost			(million $)		
Exports	793.58	1143.87	1105.90	1249.00	1376.00
Imports	2.94	5.62	5.41	5.80	9.61
Net revenue	790.64	1138.25	1100.49	1243.20	1366.39

(a) Excludes no-value exchanges.
(b) Firm exports refer to energy that must be made available when the purchaser wants it. Interruptible exports refer to energy that is made available by the supplier only when surplus energy exists.
(c) Estimated from data of major utilities.
(d) Includes purchases for export where the generation source is not identifiable.

Source: National Energy Board.

Table 15. Electricity exports and revenues by province, 1982-1984

	1982		1983		1984		% Change
	Exports GWh	Revenue $/MWh	Exports GWh	Revenue $/MWh	Exports GWh	Revenue $/MWh	in Exports 1983 to 1984
N.B.	2 989	53.2	5 311	51.2	5 693	61.5	7
Que.	8 535	34.3	10 225	33.2	11 240	34.5	10
Ont.	11 136	38.6	12 279	37.5	11 056	40.2	-10
Man.	5 217	14.8	5 967	14.9	5 196	18.2	-13
Sask.	42	36.8	61	26.8	56	26.8	-9
B.C.	5 064	28.6	3 161	25.6	7 659	15.3	142

Source: Statistics Canada Publication 57-202 1982-1983.
National Energy Board 1984.

Table 16. Gross firm and interruptible exports, 1984*

	Firm	Interruptible	Per cent Interruptible	Per cent Firm
	(kWh)			
New Brunswick	2 817 369	2 876 082	50.5	49.5
Quebec	3 081 475	8 158 624	72.6	27.4
Ontario	4 068 694	6 987 638	63.2	36.8
Manitoba	469 585	4 625 943	90.8	9.2
Saskatchewan	58 680	0	0.0	100.0
British Columbia	355 850	4 072 492	92.0	8.0
Canada	10 851 653	26 720 779	71.1	28.9

* Exchanges are excluded.

Source: National Energy Board.

Table 17. Energy sources of electricity exports by province, 1984

	Oil	Coal	Nuclear	Hydro	Other	Total
New Brunswick	24.5	9.0	35.0	-	31.5	100
Quebec	-	-	-	100.0	-	100
Ontario	-	99.0	1.0	-		100
Manitoba	-	2.0	-	98.0	-	100
Saskatchewan	-	100.0	-	-	-	100
British Columbia	-	-	-	100.0	-	100

Source: Energy, Mines and Resources Canada.

Table 18. Fuel displacement of exports

Exporting Province	Importing States	Fuel Displaced
New Brunswick	New England	Oil
Quebec	New England	Oil
	New York	Oil, coal
Ontario	New York	Oil, coal
	Michigan	Coal
	Wisconsin	Coal
Manitoba	North Dakota	Coal
	Minnesota	Coal
Saskatchewan	North Dakota	Coal
British Columbia	California	Oil, coal, gas

Source: National Energy Board.

The provincial shares of total Canadian electricity exports are shown in Table 19. Quebec and Ontario were the leading exporters in 1984, followed by British Columbia and New Brunswick.

Table 19. Provincial share of Canadian exports (per cent)

	1982	1983	1984
New Brunswick	9	14	15
Quebec	25	26	27
Ontario	33	33	27
Manitoba	15	15	12
British Columbia	18	12	19
Canada	100	100	100

Source: Energy, Mines and Resources Canada.

A summary of the forecasts by utilities, of electricity exports, is presented in Table 20. Total Canadian electricity exports are expected to continue to increase through the latter part of this decade. This increase, if it is realized, will be mostly attributable to the growth in exports from Quebec. Beyond 1990, total Canadian exports are forecast to gradually decline from 49.2 TWh in 1990 to 36.7 TWh in 2000. Manitoba is the exception to this post-1990 decline trend. Exports from Manitoba are expected to continue to increase through to the end of the century.

Table 20. Utilities' forecasts of electricity exports (TWh)

	1984 Actual	1985	1986	1990	1995	2000
New Brunswick	5.7	6.9	7.7	6.1	2.7	1.5
Quebec	11.3	13.4	19.2	22.1	17.1	15.9
Ontario	11.4	9.8	9.7	11.6	10.8	5.2
Manitoba	5.1	6.7	6.4	5.0	10.0	11.5
Saskatchewan	0.1	0.1	0.1	0.1	0.1	0.1
British Columbia	8.0	2.9	3.0	4.4	1.8	2.6
Canada	41.6	39.8	46.1	49.3	42.5	36.8

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Interprovincial Trade

The most significant changes in interprovincial transfers during 1984 were increases in net exports from Newfoundland to Quebec, where net exports increased from 31 229 GWh in 1983 to 36 043 GWh in 1984. Net exports from Quebec to Ontario increased from 5327 GWh in 1983 to 7300 GWh in 1984, up 37 per cent from the previous year. Quebec also increased its sales to New Brunswick. Net interprovincial transfers are outlined in Table 21 below. More information on exports and imports by province is provided in Figure 8 and Table A5.

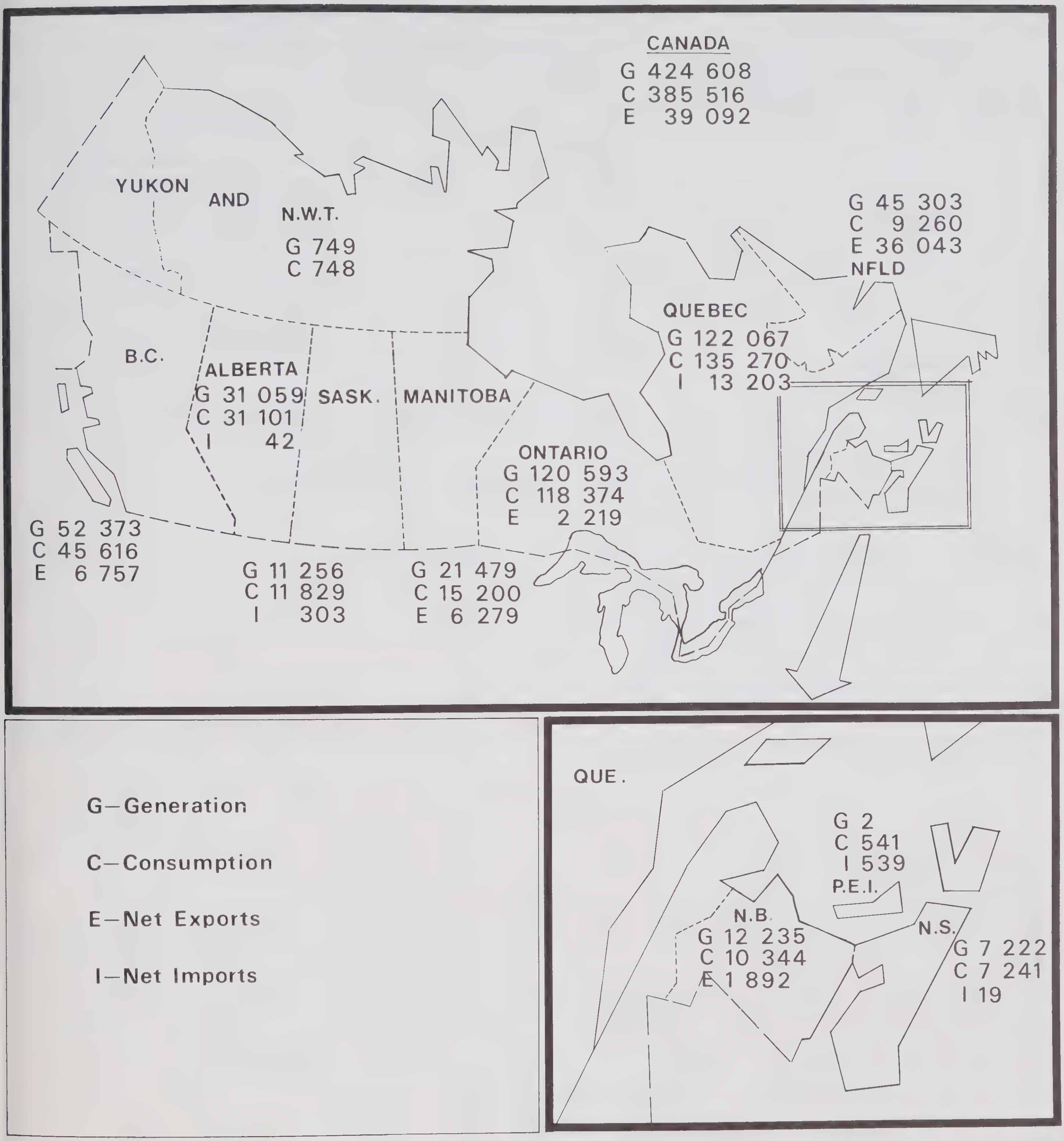
Table 21. Net interprovincial transfers (12 month period)

	GWh 1983	GWh 1984	% Growth
B.C. to Alta.	147.	36.	-75
Sask. to Alta.	1.	4.	300
Man. to Sask.	392.	327.	-17
Man. to Ont.	949.	937.	-1
Que. to Ont.	5 327.	7 300.	37
Nfld. to Que.	31 234.	36 043.	15
Que. to N.B.	3 988.	4 306.	8
N.B. to P.E.I.	519.	539.	4
N.B. to N.S.	600.	20.	-97

Source: Energy, Mines and Resources Canada.

FIGURE 8

NET TRANSFER AND EXPORTS OF ELECTRICAL ENERGY, 1984 (GWh)



FUEL REQUIREMENTS

Fuel Use in 1984

Table 22 provides information on fuels used by utilities in 1984. Ontario was the largest user of fuels for electricity production in 1984, accounting for approximately 57 per cent of the total. Alberta was the second largest user, accounting for 21 per cent. New Brunswick remains the largest user of oil. The energy sources of electricity generation are changing significantly. Oil and gas use is decreasing, coal and uranium use is increasing, and hydro is remaining relatively constant.

Provinces west of Quebec use Canadian oil, primarily light oil used in gas turbines or diesel plants. In the Territories, Canadian diesel oil is used to supply electricity to small remote communities. All oil used by the Atlantic region and Quebec is imported from outside Canada.

In 1984, about 75 per cent of the coal used for electricity generation in Ontario was imported from the United States, the remainder came from Western Canada. The coal used by Manitoba was imported from Saskatchewan. Alberta, Nova Scotia, and New Brunswick used their own coal resources for electricity generation. Saskatchewan relied primarily on its own coal, but also imported additional amounts from Alberta.

Nova Scotia and New Brunswick have used oil extensively for electricity generation, but new coal-fired and nuclear plants will increasingly displace oil. In 1984, the last of four remaining coal-fired units at Nova Scotia Power Lingan Plant was put in service. New Brunswick will double hydro electricity imports from Quebec by 1985. Hydroelectricity is expected to displace most of the oil-fired generation in Newfoundland, and Ontario has already displaced all of its major oil-fired generation. Alberta is the main user of natural gas for electricity generation, although this use is diminishing as coal-fired generation increases.

Forecast of Fuel Requirements

Forecast fuel requirements are reported in Table 23. These fuel requirements are based on the forecasts of energy generation indicated in Table 13.

Because of a substantial reduction in coal-fired generation in Ontario, coal consumption is expected to decrease from about 42 million tonnes in 1984 to 36 million tonnes in 1990, before gradually rising again to 53 million tonnes by the year 2000. The major increase in coal use will be in Nova Scotia and Alberta.

Oil consumption is expected to increase at a more moderate rate to 1.763 million cubic metres (or 11 million bbls) in 1990, and to 2.445 million cubic metres (or 15 million bbls) by the year 2000. Oil will be used primarily for peaking purposes and in remote locations.

Over the forecast period, the use of natural gas for electricity generation is projected to increase slightly from 1.067 to 1.445 billion cubic metres. Industrial establishments will be the largest users of natural gas for electricity generation; their share is predicted to account for 57 per cent for the forecast period 1984-2000.

Because nuclear energy is becoming increasingly important as a component of Canadian electricity supply, the use of uranium for electricity generation is expected to increase substantially from 909 tonnes in 1984 to about 1940 tonnes toward the end of the century, an average annual growth rate of 4.9 per cent.

Table 22. Fuel used by utilities, 1984

	Coal (thousand tonnes)	Oil (cubic metres)	Gas (million cubic metres)	Uranium (tonnes)
Newfoundland	-	326 103	-	-
Prince Edward Island	59	5 050	-	-
Nova Scotia	2 012	207 929	-	-
New Brunswick	601	568 000	-	108
Quebec	-	59 378	-	68
Ontario	13 618	15 711	3	733
Manitoba	156	151	1	-
Saskatchewan	7 920	5 000	141	-
Alberta	17 137	16 075	265	-
British Columbia	-	45 500	-	-
Yukon/NWT	-	165 000	-	-
Canada	41 503	1 413 897	410	909

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 23. Fuels required for electricity generation in Canada

	Coal (million tonnes)	Oil (million cubic metres)	Natural Gas (billion cubic metres)	Uranium (tonnes)
1985	38.0	1.8	1.2	1 313
1990	36.1	1.8	1.1	1 800
1995	42.6	2.2	1.6	2 041
2000	53.2	2.4	1.5	1 940

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Note: 1 cubic metre of oil = 6.3 bbls.
1 cubic metre of gas = 35.5 cubic feet.

TRANSMISSION

Provincial

The most extensive additions to provincial transmission lines in 1984 occurred in Quebec, where Hydro-Québec increased its in-province lines by 951 km. Alberta was the second largest builder of new transmission, with Alberta Power adding 197 km and TransAlta a further 106 km. In Manitoba, the transfer capability from the Nelson River to Southern Manitoba was increased by 500 MW. In 1985, the transfer capability will be increased by a further 500 MW. In British Columbia, transmission was increased in 1984 by the addition of three 500 kV lines.

Interprovincial

There were no additions during 1984 to provincial interconnections. Presently under construction and planned for completion in 1985 and 1986 respectively are two additional interconnections: a 130 kV line from Hydro-Québec's Madawaska substation to the substation at Edmunston, New Brunswick and a 500 kV line from Cranbrook, British Columbia to Alberta. Table 24 shows the existing interconnections, while Table 25 summarizes the proposed new additions planned for 1985-86.

International

There are now over 100 international transmission lines in place to service electricity exports to the United States. Although most of these lines are quite small, there are thirty-three bulk power interties rated at 69 kV or higher with power transfer capacity near 13 000 MW. These are outlined in Table 26.

In order to accommodate Quebec's increasing exports to the New England states, two transmission lines are under construction. One is a 120 kV line to Vermont, to be completed this year, and the other is a 450 kV direct current line to New Hampshire, to be completed in 1986. If the proposed electricity sales by Hydro-Québec to the New England Power Pool are approved by the National Energy Board, the intertie capacity between Quebec and New England will have to be strengthened from 690 to 2000 MW. The planned interconnections are outlined in Table 27.

Table 24. Provincial interconnections

Connection	Voltage (kV)	Capability Installed (MW)	Capability Firm (MW)
British Columbia - Alberta	1 x 138	110	80
Saskatchewan - Manitoba	3 x 230	400	400
Manitoba - Ontario	2 x 230	260	260
	1 x 115		
Quebec - Ontario	4 x 230	1300	1300
	9 x 120		
Quebec - Newfoundland	3 x 735	5225	4300
Quebec - New Brunswick	80(DC)	350	350
	1 x 230	150	150
	1 x 345	150	150
New Brunswick - Nova Scotia	2 x 138	600	600
	1 x 345		
New Brunswick - P.E.I.	1 x 138	200	100

Source: Energy, Mines and Resources Canada.

Table 25. Proposed provincial interconnections

Province Installed	Connections (kV)	Year	Capability Installed (MW)	Capability Firm (MW)
British Columbia - Alberta*	500 (AC)	1986	800	600
Quebec - New Brunswick*	80 (DC)	1985	350	350

* Under Construction.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 26. Major interconnections between Canada and the United States*

Province	State	Voltage (kV)	Power Transfer Capability (MW)
New Brunswick	Maine	345	600
		5 x 69	330
Quebec	New York	765	1400
	New York	2 x 120	200
	Vermont	120	100
Ontario**	New York	230	470
		230	400
		2 x 230	600
		2 x 345	2300
		4 x 69	265
	Michigan	230	535
		230	515
		345	710
		345	760
	Minnesota	120	35
Manitoba	North Dakota	230	150
	Minnesota	230	175
	Minnesota	500	1000
Saskatchewan	North Dakota	230	150
British Columbia	Washington	230	350
		230	300
		2 x 500	1400

* 35 MW capacity or over.

** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 27. Planned interconnections to the United States

Province	State	Completion Date	Voltage (kV)	Estimated Power Transfer Capability (MW)
Quebec	New Hampshire	1986	450 DC	690*
Quebec	Vermont	1985	120	200

* May be upgraded to 2000 MW by 1990.

CAPITAL EXPENDITURES

Capital Investment

Utility investment in new facilities was $6.4 billion in 1984, significantly less than the $7.8 billion spent in 1983. Approximately 56 per cent of the 1984 total was for generation, 18 per cent for transmission, 13 per cent for distribution, and the remainder for other items. Table 28 illustrates the capital-intensive nature of electricity supply and its importance in the Canadian economy, while Table 29 shows the original costs of utility fixed assets in service. The ratio of generation investment to total investment has increased from 52 per cent in 1979 to about 56 per cent in 1984. This investment pattern varies from one region to another, depending on the generation mix employed. The capital investment, per unit of capacity added, is significantly higher for hydro and nuclear capacity than for conventional thermal capacity. Hydro and nuclear generation are characterized by high capital costs and low operating costs, relative to a conventional thermal plant. In addition, hydro facilities often also require higher capital expenditures for transmission facilities, because of the remote location of the generating plants.

Table 30 presents capital expenditures for electrical system expansion in each province for 1984, and forecast capital expenditures for 1985 to 1994. Capital expenditures are forecast to decline until 1986, reflecting the completion of projects now underway and present excess generating capacity. After 1986 capital expenditures increase again, reaching a new peak in 1990.

The capital expenditures projected for this year show a major change from last year. Cumulative capital expenditures over the period 1985-1993 are expected to reach $63 billion. This level is considerably less than the previous year's forecast of $73 billion, reflecting the lower load growth forecasts in several provinces. An increasing emphasis will be put on upgrading transmission and distribution systems over the next few years, with relatively less emphasis on generation facilities. The historical data in Table 31 indicate that capital expenditures have increased at an average annual rate of 11.4 per cent since 1965. The average annual rate of inflation (measured by the Gross National Expenditure deflator) over this period was 7.3 per cent, indicating that real growth was approximately 4.1 per cent.

Financing

From 1960 to 1976 debt for utility expansion increased as a percentage of total capital employed. The debt ratio was relatively stable until 1978, and then declined for the period 1979-1982 as most utilities tried to reduce their exposure to high interest rates. However, the debt proportion increased again in 1983 as electric utilities increased their investment and borrowings. Table 32 shows electric utility debt ratios during the period 1976-1983. In 1976, debt accounted for 83 per cent of capitalization in provinces with predominantly provincially-owned utilities. It was 50 per cent in those provinces with predominantly investor-owned utilities. By 1983, debt decreased to 80 per cent for provincially-owned utilities, and to 46 per cent for investor-owned utilities.

In 1983, utilities used internally generated funds (mainly net income and depreciation) for about 28 per cent of capital expenditures. Internally generated funds are expected to meet about 30 - 35 per cent of capital requirements in the next five years.

Table 28. Electric utility capital investment

	1966-70	1971-75	1980	1981	1982	1983	1984
Investment in electric power ($ billions)	6.8	12.9	6.1	7.3	8.4	7.8	6.4
Energy share*(%)	55	56	42	40	42	42	39
Economy share*(%)	8	9	9	9	11	10	8
GNP share*(%)	1.9	2.0	2.1	2.2	2.5	2.0	1.5

* The figures indicate electrical utility capital investment as a percentage of total energy investment, investment in the economy as a whole, and GNP.

Source: Statistics Canada Publications 61-205 and 11-003E.

Table 29. Original cost of utility fixed assets in service

	1979		1981		1982		1983		1984	
	(millions)	(%)	(millions)	(%)	(millions)	(%)	(millions)	(%)	(millions)	(%)
Generation	19 177	52	24 943	53	28 352	54	34 203	56	38 301	56
Transmission	7 421	20	9 632	20	10 828	20	12 035	20	13 352	19
Distribution	7 950	21	9 554	20	10 650	20	11 836	19	12 787	19
Other	2 601	7	3 145	7	3 031	6	3 409	5	4 360	6
Total	37 149	100	47 274	100	52 861	100	61 483	100	68 800	100

Source: Statistics Canada Publication 57-202
Data for 1984 preliminary

Table 30. Capital expenditures by electric utilities

	(Millions of Current Dollars)										
	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Newfoundland	135	75	72	201	806	1498	1758	1437	1152	571	400
Prince Edward Island	5	7	11	12	6	6	7	8	9	10	10
Nova Scotia	130	57	74	86	65	147	308	383	301	277	277
New Brunswick	136	55	66	94	98	99	82	71	74	75	88
Quebec	1681	1784	1939	1967	1994	2065	1730	1810	1940	2076	2526
Ontario	2842	2833	2538	2476	2280	1953	2094	2030	1 807	1 877	1 890
Manitoba	125	255	313	503	516	517	560	426	453	388	931
Saskatchewan	256	264	190	250	377	440	422	364	371	431	533
Alberta	656	656	615	661	617	702	913	790	788	801	833
British Columbia	448	217	124	116	145	185	230	213	202	234	294
Yukon, NWT	30	6	6	17	5	13	2	4	4	7	8
Canada	6426	6209	5948	6383	6909	7625	8106	7536	7 101	6 747	7 790

Source: Energy, Mines and Resources - Utility Questionnaire
Fiscal and calendar years combined
Data for 1984 is preliminary

Table 31. Historical electric utility investment

Year	Construction			Sub-Total	Machinery and Equipment	Total
	Generation	Transmission and Distribution*	Other			
	(millions of current dollars)					
1965	438	277	12	727	212	939
1966	493	281	13	787	356	1413
1967	577	262	36	875	390	1265
1968	533	301	54	889	443	1332
1969	511	281	63	856	546	1403
1970	581	449	28	1057	554	1610
1971	572	472	36	1079	668	1747
1972	636	449	50	1135	619	1754
1973	808	539	69	1417	827	2244
1974	1049	598	53	1700	1054	2753
1975	1691	874	96	2661	1296	3957
1976	1803	821	30	2654	1574	4229
1977	2205	911	43	3158	1726	4884
1978	2339	1199	233	3761	2175	5936
1979	2516	1424	181	4121	2243	6364
1980	2470	1433	95	3998	2111	6109
1981	2768	1554	92	4414	2905	7319
1982	3153	1818	320	5322	3086	8408
1983	2663	1755	202	4620	3150	7770
1984(a)	-	-	-	3207	3219	6426

* Transmission and distribution includes street lighting. Generation includes transformer stations, dams and reservoirs.

(a) Preliminary actual data, no breakdown available.

Note: The totals may not correspond with the sum of the elements due to rounding.

Source: Statistics Canada Publications 57-202, 61-205, and Canada Year Book 1968-79.

Table 32. Electric utility debt ratio

	1976	1977	1978	1979	1980	1981	1982	1983
				(%)				
Newfoundland	79	76	76	76	74	71	73	78
Prince Edward Island	53	53	52	53	54	55	55	68
Nova Scotia	103	102	99	98	95	97	97	96
New Brunswick	92	92	93	93	91	91	90	89
Quebec	76	76	76	75	75	75	75	75
Ontario	77	77	78	78	78	78	80	79
Manitoba	97	97	96	94	94	95	96	96
Saskatchewan	73	77	78	78	80	85	89	92
Alberta	49	47	44	45	42	42	49	70
British Columbia	94	95	94	86	85	85	85	86
Yukon and Northwest Territories	102	99	98	98	98	99	98	96
Canada	80	80	80	78	77	77	78	80

Debt ratio = debt/(debt + equity).
Debt: Long-term + short-term loans and notes payable.
Equity: Total of capital, reserves, and surplus.

Source: Statistics Canada Publication 57-202.

COSTING AND PRICING

Electricity Supply Costs

The unit cost of supplying additional electricity increased rapidly during the period 1973-1982. However, cost increases have moderated significantly since then; adjusted for inflation, the real increases in the cost of electricity have been small. This is expected to be the case for the next several years.

In the 1973-1982 period, there were two basic reasons for the rapid increases in the cost of electricity: the high rate of inflation and the increased cost of fossil fuels. High levels of inflation affect the electric utility industry in two ways, by increasing the capital cost of constructing additional facilities and by increasing the cost of borrowed funds.

The average interest rate on new long-term utility debt for the period 1968-1984 is shown in Figure 9. Interest rates started to rise in 1973, reached a peak in 1981 and 1982, and then dropped substantially in 1983. The index of electric utility construction costs is presented in Figure 10. It shows the significant increase in utility construction costs between 1973 and the present, a trend shared by most capital projects. In general, electricity construction costs tend to parallel the Consumer Price Index.

The increases in fossil fuel costs experienced since 1969 are summarized in Figure 11. It is clear from Figure 11 that fuel costs for electricity generation were generally stable prior to the oil crisis of 1973, and that they began to rise thereafter. For Canada as a whole, the fuel cost per kWh generated from fossil fuels increased more than four fold between 1973 and 1983, from 3.1 mills to 13.2 mills. The increase in the cost of fuel from oil generation was much more dramatic, growing from 7.1 mills to 57.3 mills per kWh during the same period, an average annual increase of 23 per cent. The impact of the cost increase varies between regions of the country and depends on the type of fuel used, its source, and the percentage of total energy supply derived from fossil fuel plants.

Pricing

The average revenue from electricity sales for each province is provided in Table 33. Because electricity rates are regulated to cover costs, the average revenue per unit of electricity started to increase substantially in 1975, with the escalation in the cost of electricity generation. The average annual growth in the unit revenue for Canada as a whole was 13 per cent during the period 1974-1983. The national inflation rate, as measured by the Consumer Price Index (CPI), was 9.3 per cent over the same period.

Costs increased more rapidly in some regions than others, because of differences in generation mix, fuels used, and rates of system expansion to meet increased demands for electricity. Table 34 gives monthly electricity costs for selected Canadian cities. Table 35 details the average annual rate increases for customers in each province since 1976.

Figure 12 illustrates the movements of the electricity and oil/gas components of the CPI, and the movement of the Energy Price Index, as well as the CPI itself. It indicates that the electricity price component increased more slowly than, or equal to, the rate of increase of the CPI for the period 1971-1976. Since 1977, the electricity price has been consistantly greater than the CPI; however, it has increased significantly more slowly than the oil and gas price indices.

FIGURE 9

AVERAGE INTEREST RATE ON PUBLIC UTILITY NEW LONG-TERM DEBT

1960-1984

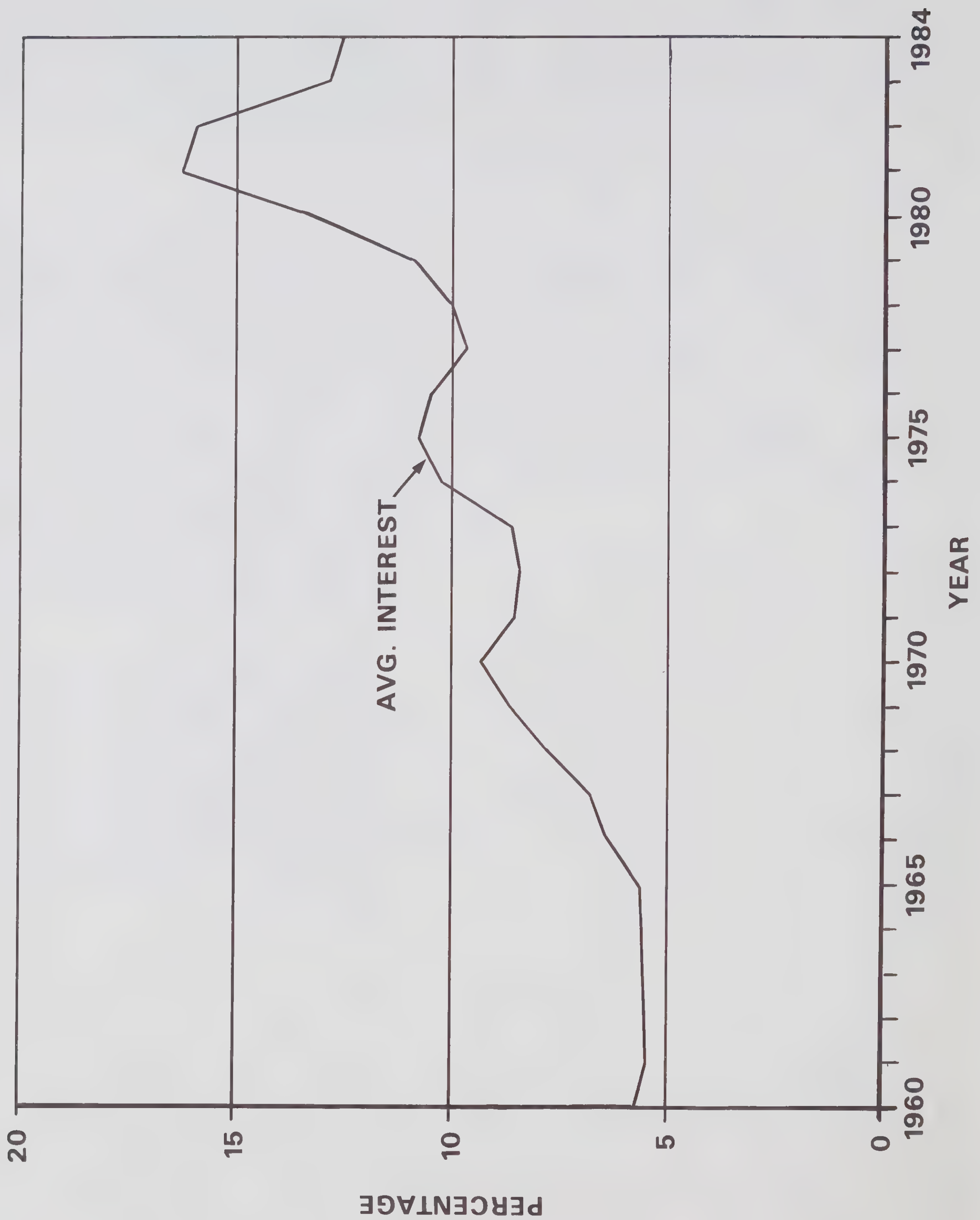


FIGURE 10

PRICE INDEX TRENDS IN UTILITY CONSTRUCTION

1968-1984

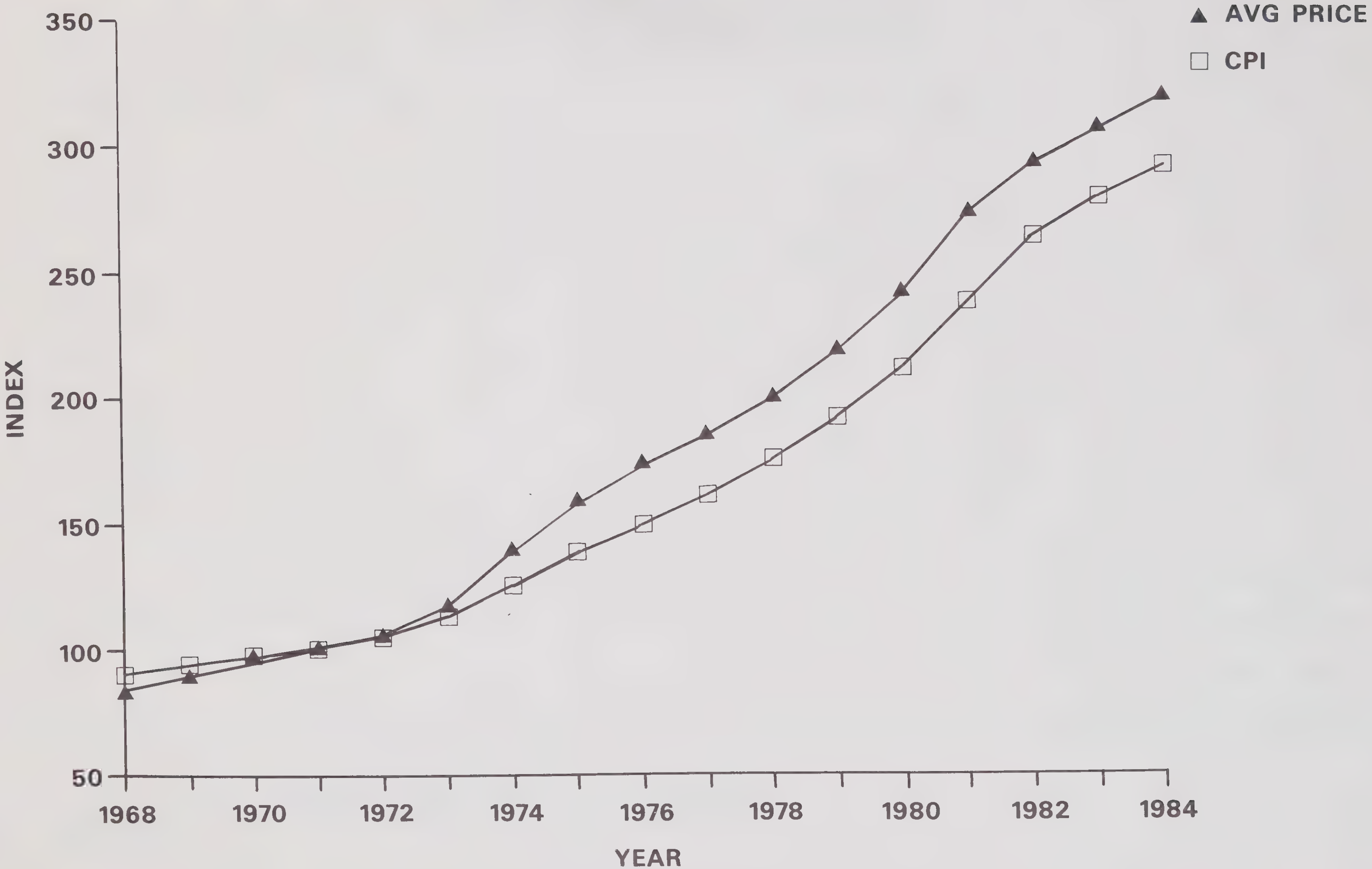


FIGURE 11

UNIT COST OF FOSSIL FUEL FOR ELECTRICITY PRODUCTION 1969-1983

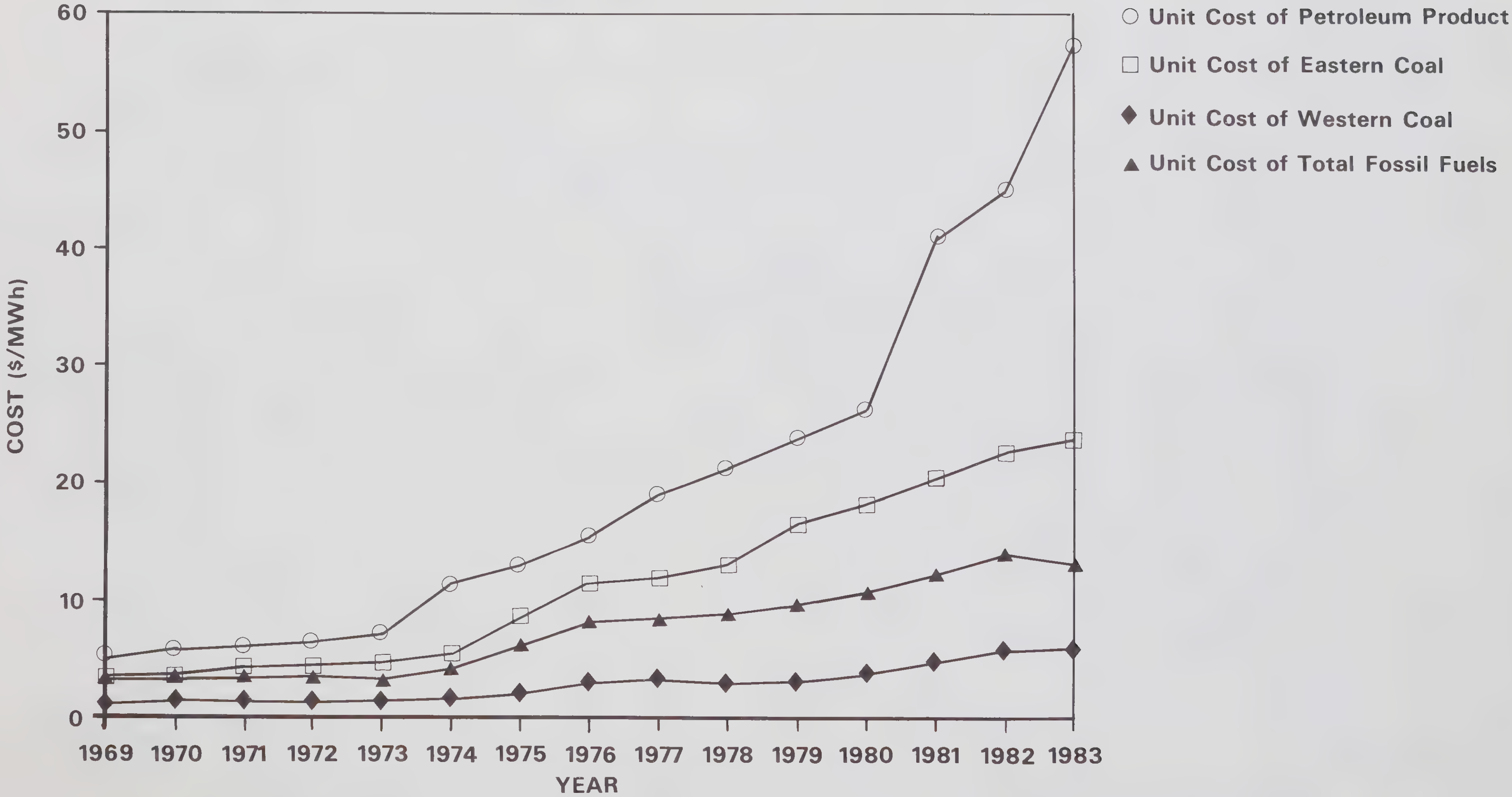


Table 33. Average revenue from electricity sales by province

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983
	(current cents/kWh)									
Newfoundland	1.3	1.4	1.4	1.7	2.0	2.2	2.3	2.8	3.6	3.7
Prince Edward Island	3.7	4.1	5.1	5.9	6.4	7.2	8.1	10.0	12.0	12.4
Nova Scotia	2.0	2.5	2.8	3.9	4.4	4.6	4.5	4.9	5.9	6.9
New Brunswick	1.6	1.9	2.0	2.4	3.2	3.7	4.1	4.8	5.1	5.3
Quebec	1.1	1.3	1.4	1.5	1.7	2.0	2.2	2.6	3.1	3.3
Ontario	1.4	1.6	1.8	2.3	2.4	2.6	2.9	3.2	3.6	3.9
Manitoba	1.2	1.4	1.7	1.9	2.3	2.7	2.8	2.8	2.9	3.0
Saskatchewan	1.6	1.8	2.1	2.4	2.7	2.7	2.9	3.6	4.0	4.2
Alberta	1.7	2.0	2.4	2.7	3.1	3.2	3.4	4.1	4.9	5.2
British Columbia	1.4	1.6	1.8	2.1	2.2	2.4	2.6	3.0	3.8	3.8
Yukon	2.6	2.7	3.5	4.1	4.4	4.9	5.3	6.7	8.3	8.6
Northwest Territories	3.6	4.0	5.2	6.9	7.7	9.0	10.0	11.5	14.8	18.0
Canada	1.3	1.5	1.7	2.0	2.3	2.5	2.8	3.1	3.7	3.9

Source: Statistics Canada Publication 57-202

Table 34. Monthly electricity costs for selected Canadian cities, January 1984

Sector	Residential	Commercial	Industrial
Billing Demand (KW)	-	100	1000
Consumption (KWh)	1000	25 000	400 000
	($)		
St. John's	64.73	1 656.25	20 358.62
Charlottetown	116.62	3 368.94	43 745.12
Halifax	65.22	2 027.21	21 104.61
Moncton	57.43	1 865.70	18 450.00
Montreal	37.07	1 261.00	14 719.50
Ottawa	42.45	1 117.85	15 952.85
Toronto	46.90	1 467.90	17 568.00
Winnipeg	33.78	892.87	10 141.70
Regina	41.40	1 384.15	16 859.17
Calgary	49.65	1 445.54	16 670.62
Edmonton	46.00	1 367.60	17 755.59
Vancouver	48.26	1 206.05	14 517.56
Whitehorse	66.30	2 130.00	-
Yellowknife	95.00	3 255.00	48 605.00

Source: Statistics Canada Publication 57-203.

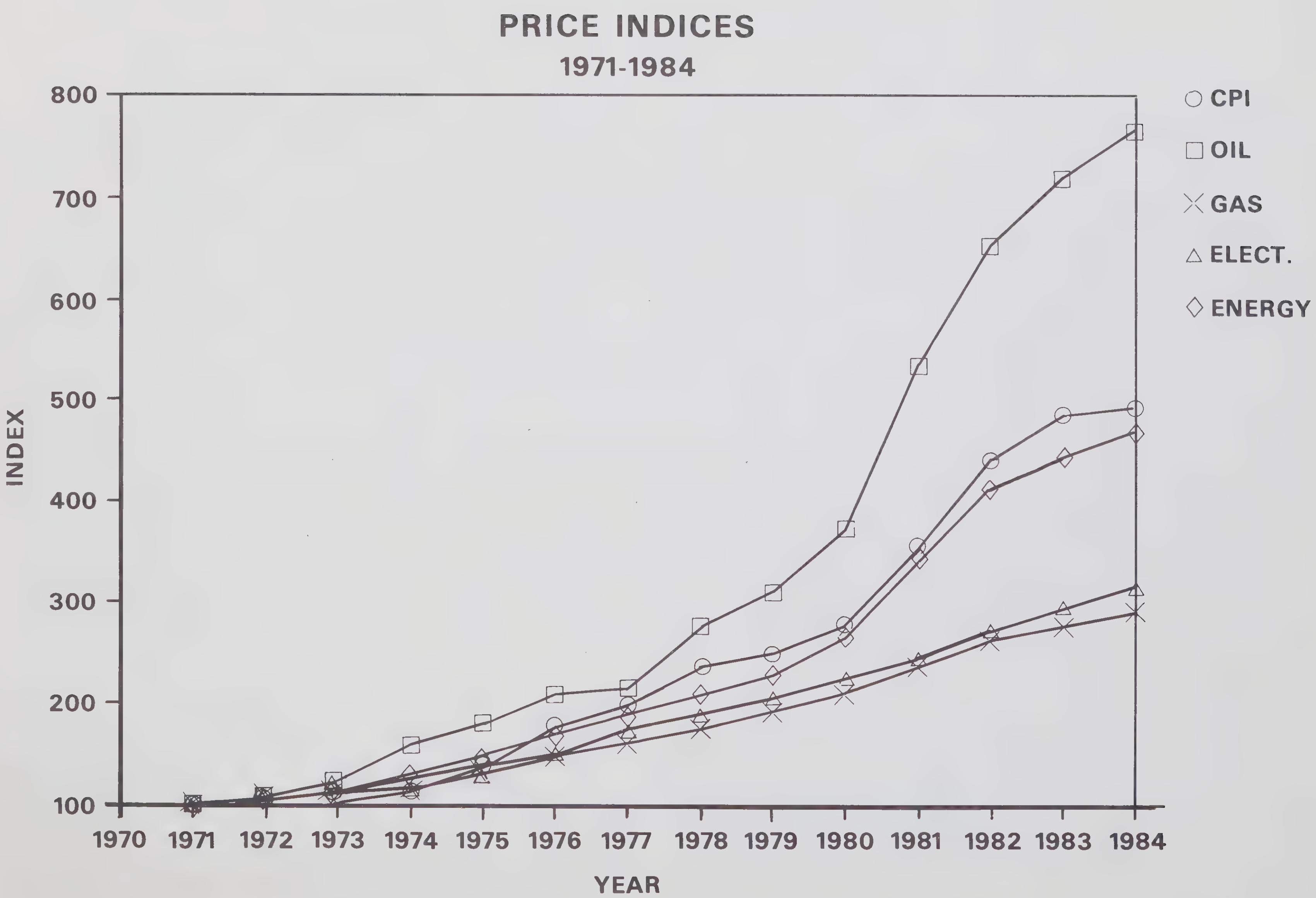
Table 35. Average annual rate increases, 1976-1984

Utility	Rate Changes (%): Average of all Customer Classes								
	1976	1977	1978	1979	1980	1981	1982	1983	1984
Newfoundland Hydro	14.0	8.4	25.0	-	19.0	15.8	-	18.2	-
Newfoundland Light & Power	13.4	9.8	21.2	12.4	11.8	14.6	-	12.0	-
Maritime Electric	(8.0)	17.0	13.0	-	13.1	21.4	-**	-	-
Nova Scotia Power	-	43.0	14.0	12.5	-(2)	-	-	36.6	-
New Brunswick Power	12.0	16.6	9.9	7.9	7.8	9.8	-	8.8	6.2
Hydro-Québec	10.3	9.9	18.7	13.7	13.3	10.6	16.3	7.3	4.0
Ontario Hydro	14.9	25.6	5.7	7.7	7.3	10.0	10.0	8.2	7.5
Manitoba Hydro	16.6	15.0	14.9	14.4	-(1)	-	-	9.5	7.9
Saskatchewan Power	13.0	17.0	3.3	8.3	7.9	16.1	-	12.6	9.2
Edmonton Power	10.1	6.0	8.1	-	26.0	12.0	13.2	8.0	5.0
TransAlta Utilities	25.8	14.7	15.6	7.5	-	13.0	4.0	15.0	-
Alberta Power	11.4	20.2	-	-	12.3	28.9	-11.6*	-	-
B.C. Hydro	14.2	12.1	13.4	5.5	7.6	2.6	20.0*	6.0	6.5

(1) The provincial government froze rates from 1979 until 1983.
(2) The provincial government froze rates in 1980.
* Based on residential category. Reduction in rates is a result of Alberta Electric Energy Marketing Agency rebate.
** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.

Source: Energy, Mines and Resources

FIGURE 12


PRICE INDICES
1971-1984
INDEX
800
700
600
500
400
300
200
100
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
YEAR
CPI
OIL
GAS
ELECT.
ENERGY

Appendices

A1. Installed capacity and electrical energy consumption in Canada, 1920-1984

A2. Installed and proposed generating capacity, 1984

A3. Conventional thermal capacity by principal fuel type

A4. Electrical energy production by principal fuel type

A5. Provincial electricity imports and exports

A6. Generation capacity by type and province

A7. Installed generating capacity expansion in Canada by station. Major additions in 1984 and projections 1985-2004.

Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1984

Year	Installed Capacity: Thermal: Conventional (MW)	Installed Capacity: Thermal: Nuclear (MW)	Installed Capacity: Thermal: Sub-Total (MW)	Installed Capacity: Hydro (MW)	Installed Capacity: Total (MW)	Electrical Energy Consumption(a) (GWh)	Average Demand(b) (MW)	Peak Demand(c) (MW)	Reserve Margin(d) (MW)	Reserve Margin(d) %	Load Factor(e) %
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 657	23 049	109 302	12 477	17 264	5 785	34	72
1961	5 072	-	5 072	19 019	24 091	110 950	12 666	18 353	5 738	31	69
1962	5 609	20	5 629	19 338	24 967	116 135	13 257	18 937	6 030	32	70
1963	6 180	20	6 200	20 101	26 301	121 510	13 871	20 783	5 518	27	67
1964	6 694	20	6 714	20 313	27 027	133 949	15 291	22 516	4 511	20	68
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1966	8 307	20	8 327	22 438	30 765	156 956	17 917	25 921	4 844	19	69
1967	9 373	240	9 613	23 353	32 966	165 812	18 928	27 812	5 154	19	68
1968	10 711	240	10 951	24 957	35 908	176 841	20 187	30 300	5 608	19	67
1969	12 321	240	12 561	27 031	39 592	189 522	21 635	32 092	7 500	23	67
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1971	14 504	1 570	16 075	30 601	46 676	212 882	24 302	35 720	10 956	31	68
1972	15 318	2 126	17 444	32 500	49 944	231 557	26 433	38 921	11 023	28	68
1973	17 711	2 400	20 111	34 266	54 376	249 298	28 459	42 699	11 677	27	67
1974	18 085	2 666	20 751	36 779	57 530	266 956	30 747	42 528	15 002	35	72
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 537	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	27 853	5 866	33 719	47 919	81 634	340 069	38 821	59 170	22 464	38	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983r	30 748	7 505	38 253	51 274	89 527	359 764	41 077	66 866	22 626	34	61
1984*	31 068	9 587	40 645	54 875	95 530	385 516	44 009	69 044	26 486	38	64

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81, Statistics Canada Publication. 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr) (c) Statistics Canada Publication 57-204

(d) Reserve margin = $\frac{\text{(Installed capacity - Peak demand)}}{\text{Peak demand}}$ (e) Load Factor = Average demand ÷ Peak demand

Table A2. Installed and proposed generating capacity, 1984 (MW)

	Hydro	Nuclear	Conventional Thermal*	Total	% of Canadian Total
Newfoundland	6 215	0	752	6 967	7.29
Prince Edward Island	0	0	122	122	.13
Nova Scotia	386	0	1 982	2 368	2.48
New Brunswick	901	680	1 904	3 485	3.65
Quebec	24 762	951	1 119	26 832	28.09
Ontario	7 131	7 956	13 672	28 759	30.10
Manitoba	3 641	0	501	4 142	4.34
Saskatchewan	576	0	2 074	2 650	2.77
Alberta	734	0	6 893	7 627	7.98
British Columbia	10 379	0	1 867	12 246	12.82
Yukon	102	0	40	142	.15
Northwest Territories	49	0	142	191	.20
Canada Total					
At Dec. 31, 1984**	54 876	9 587	31 068	95 531	100.00
Percent of Total Capacity, End 1984	57.44	10.04	32.52	100	-
Net Additions					
During 1984**	3 601	1 813	623	6 037	-
Planned Additions					
During 1985	1 640	462	1 300	3 402	-

* Details provided in Table A3. Conventional thermal includes steam, gas turbine, internal combustion.

** Preliminary Data.

Source: Energy, Mines and Resources - Utility Questionnaire

Table A3. Conventional thermal capacity by principal fuel type. Preliminary figures as at December 31, 1984 (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other*	Total
Newfoundland	-	503	-	-	503	170	-	170	79	-	79	-	752	-	-	752
Prince Edward Island	-	71	-	-	71	41	-	41	11	-	11	-	122	-	-	122
Nova Scotia	946	831	-	-	1 777	205	-	205	1	-	1	946	1037	-	-	1 982
New Brunswick	285	1 551	-	40	1 876	23	-	23	5	-	5	285	1 579	-	40	1 904
Quebec	-	630	-	10	640	363	-	363	116	-	116	-	1 110	-	10	1 119
Ontario	10 35	2 298	165	86	12 899	581	181	762	4	6	10	10 350	2 883	352	86	13 671
Manitoba	419	-	4	23	446	24	-	24	32	-	32	419	55	4	23	501
Saskatchewan	1 772	-	106	43	1 922	-	146	146	7	-	7	1 772	7	252	43	2 074
Alberta	4 873	66	1 279	107	6 325	-	524	524	14	30	44	4 873	80	1 833	107	6 893
British Columbia	-	124	1 038	256	1 419	185	154	339	91	18	109	-	400	1 210	256	1 867
Yukon	-	-	-	-	-	-	-	-	40	-	40	-	40	-	-	40
NWT	-	-	-	-	-	-	-	-	141	-	141	-	141	-	-	141
Canada	18 645	6 073	2 592	564	27 876	1 592	1 005	2 598	540	54	595	18 645	8 206	3 652	564	31 068

* Mainly wood wastes and black liquor.

Source: Energy, Mines and Resources - Utility Questionnaire

Table A4. Electrical energy production by principal fuel type 1984 (GWh)

	Conventional Thermal								% of Total	% Generated By	
	Coal	Oil	Gas*	Sub-Total	Nuclear	Hydro	Other	Total	Generation	Utilities	Industry
Newfoundland	0	781	0	781	0	44 522	0	45 303	10.7	98.9	1.1
Prince Edward Island	141	2	0	132	0	0	0	143	0.0	100.0	0.0
Nova Scotia	2 952	3 239	0	6 191	0	1 031	0	7 222	1.7	95.1	4.9
New Brunswick	477	3 426	0	3 903	5 011	3 093	87	12 094	2.8	94.3	5.6
Quebec	0	141	0	141	3 422	118 504	1	122 067	28.7	85.2	14.7
Ontario	33 339	366	979	38 684	40 833	40 836	240	120 593	28.5	96.8	3.1
Manitoba	211	28	2	241	0	21 226	12	21 479	5.1	99.7	0.3
Saskatchewan	9 097	34	482	9 613	0	1 705	208	11 526	2.7	96.8	3.1
Alberta	27 747	99	1 326	29 172	0	1 427	460	31 059	7.3	91.5	8.5
British Columbia	0	456	1 381	1 837	0	50 244	292	52 373	12.3	78.7	21.3
Yukon/NWT	0	198	0	198	0	550	0	748	0.2	100.0	.0
Canada	77 964	8 770	4 170	90 904	49 266	283 138	1 300	424 608	100.0	91.1	8.9

* Estimated values

Source: Statistics Canada

Table A5. Provincial electricity imports and exports (GWh)

		Interprovincial Trade			International Trade			
	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
Newfoundland	1984	36 043	-	36 043				36 043
	1983r	31 229	-	31 229	-	-	-	31 229
	1982	35 777	-	35 777	-	-	-	35 777
Prince Edward Island	1984	-	539	-539	-	-	-	-539
	1983	-	519	-519	-	-	-	-519
	1982	-	476	-476	-	-	-	-476
Nova Scotia	1984	282	301	-19				-19
	1983r	121	737	-616	-	-	-	-616
	1982	133	216	-83	-	-	-	-83
New Brunswick	1984	840	4 588	-3 748	5 657	17	5 640	1 892
	1983r	1 258	4 092	-2 834	5 312	70	5 242	2 408
	1982	692	3 746	-3 054	3 029	71	2 958	-96
Quebec	1984	11 668	36 113	-24 445	11 250	8	11 242	-13 203
	1983r	9 349	31 281	-21 932	10 228	9	10 219	-11 713
	1982	9 386	35 833	-26 447	8 530	7	8 523	-17 924
Ontario	1984	64	8 302	-8 238	11 370	913	10 457	2 219
	1983r	64	6 333	-6 269	12 657	469	12 188	5 919
	1982	60	6 845	-6 785	11 168	403	10 765	3 980
Manitoba	1984	2 565	1 300	1 265	5 057	43	5 014	6 279
	1983r	2 565	1 222	1 343	5 994	19	5 975	7 318
	1982	2 460	1 088	1 372	5 255	214	5 041	6 413
Saskatchewan	1984	1 302	1 625	-323	86	66	20	-303
	1983r	1 211	1 610	-399	81	84	-3	-402
	1982	1 087	1 388	-301	60	31	29	-272
Alberta	1984	262	302	-40	-	2	-2	-42
	1983r	46	166	-120	-	2	-2	-122
	1982	189	447	-258	-	2	-2	-260

Table A5. Provincial electricity imports and exports (GWh) (Cont'd)

		Interprovincial Trade			International Trade			
	Year	Exports	Imports	Net Exports	Exports	Imports	Net Exports	Total Net Exports
British Columbia	1984	298	262	36	8 015	1 294	6 721	6 757
	1983r	163	46	117	4 708	2 242	2 466	2 583
	1982	444	189	255	6 171	2 119	4 052	4 307
Yukon	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
	1982	-	-	-	-	-	-	-
Northwest Territories	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
	1982	-	-	-	-	-	-	-
Canada	1984				41 435	2 343*	39 092	39 092
	1983r	-	-	-	38 980	2 895*	36 085	36 085
	1982	-	-	-	34 213	2 847*	31 366	31 366

r Revised
* Includes exchanges

Source: Statistics Canada

Table A6. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total End 1983	502.60	170.39	78.75	-	751.74	6 212.70	6 964.44
Additions 1984	-	-	-	-		2.28	2.28
Total End 1984	502.60	170.39	78.75	-	751.74	6 214.98	6 966.72
Additions Proposed							
1985	-	-	-	-	-	5.51	5.51
1986	-	-	-	-	-	127.00	127.00
Total End 1986	502.60	170.39	78.75	-	751.74	6 342.59	7 094.33
PRINCE EDWARD ISLAND							
Total End 1983	70.50	40.85	11.14	-	122.49	-	122.49
Additions 1984	-	-	-	-	-	-	-
Total End 1984	70.50	40.85	11.14	-	122.49	-	122.49
NOVA SCOTIA							
Total End 1983	1 626.88	205.00	0.60	-	1 832.48	366.40	2 198.88
Additions 1984	150.00	-	-	-	150.00	20.00	170.00
Total End 1984	1 776.88	205.00	0.60	-	1 982.48	386.40	2 368.88
Additions Proposed							
1985	150.00	-	-	-	150.00		150.00
1986	-	-	-	-	-	7.30	7.30
1991	300.00	-	-	-	300.00	-	300.00
Total End 1991	2 226.88	205.00	0.60	-	2 432.48	393.70	2 826.18
NEW BRUNSWICK							
Total End 1983	1 876.08	23.38	4.84	680.00	2 584.30	901.03	3 485.33
Additions 1984	-	-	-	-	-	-	-
Total End 1984	1 876.08	23.38	4.84	680.00	2 584.30	901.03	3 485.33

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
QUEBEC							
Total End 1983	639.75	362.88	114.45	951.40	2 068.48	22 585.02	24 653.50
Additions 1984	-	-	2.02		2.02	2 176.48	2 176.48
Total End 1984	639.75	362.88	116.47	951.40	2 070.50	24 761.50	26 829.98
Additions Proposed							
1985	-	-	-	-	-	883.50	883.50
1986	-	-	-	-	-	-	-
1987	-	-	-	-	-	21.00	21.00
1988	-	-	-	-	-	-	-
1989	-	-	-	-	-	988.00	988.34
1990	-	-	-	-	-	-	-
1991	-	-	-	-	-		-
1992	-	-	-	-	-	633.00	633.00
1993	-	-	-	-	-	734.00	734.00
1994	-	-	-	-	-	736.17	736.17
Total End 1994	639.75	362.88	116.47	951.40	2 070.50	28 757.17	30 827.67
ONTARIO							
Total End 1983	12 897.73	729.59	10.02	6 140.00	19 777.34	7 131.20	26 908.54
Additions 1984	-	33.00	2.02	1 816.00	1 851.02		1 851.02
Total End 1984	12 897.73	762.59	12.04	7 956.00	21 628.36	7 131.20	28 759.58
Additions Proposed							
1985	206.00	104.00	-	1 300.00	1 610.00	-	1 610.00
1986	-	-	-	784.00	784.00	-	784.00
1987	-	-	-	784.00	784.00	-	784.00
1988	-	-	-	881.00	881.00	-	881.00
1989	-	-	-	881.00	881.00	-	881.00
1990	-	-	-			-	-
1991	-	-	-	881.00	881.00	-	881.00
1992	-	-	-	881.00	881.00	-	881.00
Total End 1992	13 103.73	866.59	12.04	14 348.00	28 330.36	7 131.20	35 461.56

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
MANITOBA							
Total End 1983	445.80	23.80	31.63	-	501.23	3 641.10	4 142.33
Additions 1984	-	-	-	-	-	-	-
Total End 1984	445.80	23.80	31.63	-	501.23	3 641.10	4 142.33
Additions Proposed							
1990	-	-	-	-	-	256.00	256.00
1991	-	-	-	-	-	640.00	640.00
1992	-	-	-	-	-	384.00	384.00
1996	-	-	-	-	-	87.50	87.50
1997	-	-	-	-	-	262.50	262.50
1998	-	-	-	-	-		
1999	-	-	-	-	-	130.00	130.00
2000	-	-	-	-	-	520.00	520.00
2001	-	-	-	-	-	650.00	650.00
Total End 2001	445.80	23.80	31.63	-	501.23	6 571.10	7 072.33
SASKATCHEWAN							
Total End 1983	1 921.76	103.92	6.75	-	2 032.43	575.50	2 607.93
Additions 1984		42.00	-	-	42.00	-	42.00
Total End 1984	1 921.76	145.92	6.75	-	2 074.43	575.50	2 649.93
Additions Proposed							
1985	-	-	-	-	-	168.00	168.00
1986	-	-	-	-	-	84.00	84.00
Total End 1986	1 921.76	145.92	6.75	-	2 074.43	827.50	2 901.93

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ALBERTA							
Total End 1983	5 930.91	524.10	44.26	-	6 499.27	733.70	7 232.97
Additions 1984	394.00	-	-	-	394.00	-	394.00
Total End 1984	6 324.91	524.10	44.26	-	6 893.27	733.70	7 626.97
Additions Proposed							
1985	-	-	-	-	-	-	-
1986	380.00	-	-	-	380.00	-	380.00
1987	-	-	-	-	.00	5.00	5.00
1988	400.00	-	-	-	400.00	-	400.00
1989	400.00	-	-	-	400.00	-	400.00
1990	380.00	-	-	-	380.00	-	380.00
1992	750.00	-	-	-	750.00	-	750.00
1993	750.00	-	-	-	750.00	-	750.00
1994	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-
1996	375.00	-	-	-	375.00	759.00	1 134.00
1997	375.00	-	-	-	375.00	906.00	1 281.00
1998	-	-	-	-	.00	151.00	151.00
1999	375.00	-	-	-	375.00	-	375.00
2000	750.00	-	-	-	750.00	-	750.00
2001		100.00	-	-	100.00		100.00
2002	-	200.00	-	-	200.00	-	200.00
2003	750.00		-	-	750.00	-	750.00
2004		100.00	-	-	100.00	-	100.00
Total End 2004	12 009.91	924.10	44.26	-	12 978.27	2 554.70	15 532.97

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
BRITISH COLUMBIA							
Total End 1983	1 418.89	339.20	108.94	-	1 867.03	8 996.54	10 863.57
Additions 1984	-	-	-	-	-	1 382.00	1 382.00
Total End 1984	1 418.89	339.20	108.94	-	1 867.03	10 378.54	12 245.57
Additions Proposed							
1985	-	-	-	-	-	460.75	460.75
2000	-	-	-	-	-	120.00	120.00
2001	-	-	-	-	-	60.00	60.00
2002	-	-	-	-	-	110.00	110.00
2003	-	-	-	-	-	165.00	165.00
Total End 2003	1 418.89	339.20	108.94	-	1 867.03	11 294.29	13 161.32
YUKON and NWT							
Total End 1983	-	-	181.13	-	181.13	130.70	311.83
Additions 1984	-	-	-	-	-	20.00	20.00
Total End 1984	-	-	181.13	-	181.13	150.70	331.83
Additions Proposed							
1985			1.50		1.50		1.50
1988						.75	.75
Total End 1988	-	-	182.63	-	182.63	151.45	334.08

Table A6. Generation capacity by type (MW) (Cont'd)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total End 1983	27 330.90	2 523 11	592.51	7 771.40	38 217.92	51 273.89	89 491.81
Additions 1984	544.00	75.00	4.04	1 816.00	2 439.04	3 600.76	6 039.80
Total End 1984	27 874.90	2 598.11	596.55	9 587.40	40 656.96	54 874.65	95 531.61
Additions Proposed							
1985	356.00	104.00	1.50	1 300.00	1 761.50	1 639.55	3 401.05
1986	380.00	-	-	784.00	1 164.00	91.61	1 255.61
1987	.00	-	-	784.00	784.00	26.00	810.00
1988	400.00	-	-	881.00	1 281.00	.75	1 281.75
1989	400.00	-	-	881.00	1 281.00	988.00	2 269.00
1990	380.00	-	-	-	380.00	256.00	636.00
1991	300.00	-	-	881.00	1 181.00	640.00	1 821.00
1992	750.00	-	-	881.00	1 631.00	1 017.00	2 648.00
1993	750.00	-	-	-	750.00	734.00	1 484.00
1994	-	-	-	-	-	736.17	736.17
1995	-	-	-	-	-	-	-
1996	375.00	-	-	-	375.00	846.50	1 221.50
1997	375.00	-	-	-	375.00	1 168.50	1 543.50
1998	-	-	-	-	-	151.00	151.00
1999	375.00	-	-	-	375.00	130.00	505.00
2000	750.00	-	-	-	750.00	640.00	1 390.00
2001	-	100.00	-	-	100.00	710.00	810.00
2002		200.00	-	-	200.00	110.00	310.00
2003	750.00	-	-	-	750.00	165.00	915.00
2004	-	100.00	-	-	100.00	.00	100.00
Total End 2004	34 215.90	3 102.11	598.05	15 979.40	53 895.46	64 924.73	118 820.19

Source: Energy, Mines and Resources - Utility Questionnaire

Table A7. Installed generating capacity expansion in Canada by station. Major 1984 additions and projected 1985 - 2004

Province and Station	Type*	Additions in 1984	Year	Additions Proposed	Status	Proposed Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Topsail	H	2.25			I	3.45
Lookout Brook	H	2.65			I	7.85
Cat Arm	H		1985	2 x 63.50	C	127.00
Petty Harbour	H		1985	1 x 0.30	P	
			1986	1 x 0.30	P	5.61
NOVA SCOTIA						
Annapolis Royal	H	20.0			I	20.00
Lingan	S(C)	150.0			I	
			1985	150.0	C	600.00
Fall River	H		1986	0.5	P	0.50
Nictaux	H		1986	6.8	P	6.80
New Thermal	S(C)		1991	300.0	P	300.00
QUEBEC						
La Grande -						
LG-3	H	2 x 192			I	2 304.00
Lac Robertson	H		1987	2 x 10.5	P	21.00
			1992	2 x 316.5	P	
La Grande 2	H		1993	2 x 317	P	
			1994	2 x 316.5	P	3 820.00
LG-4	H	6 x 294.5			I	
			1985	4 x 294.5	C	2 650.50
Manic 5	H		1989	4 x 247	C	2 280.00
Various Locations	H		1993	100	P	
			1994	100	P	
	IC	2.02			I	
	H	25.48			I	
ONTARIO						
Atikokan	S(C)		1985	206	C	
Bruce B	N	784	1985	784	C	
			1986	784	C	
			1987	784	C	
	GT	2 x 16.5			I	3 169.00
Darlington	N		1988	881	C	
			1989	881	C	
			1991	881	C	
			1992	881	C	
	GT		1985	4 x 26	P	3 628.00

Table A7. Installed generating capacity expansion in Canada by station. Major 1984 additions and projected 1985 - 2004 (Cont'd)

Province and Station	Type*	Additions in 1984 (MW)	Year	Additions Proposed (MW)	Status	Proposed Plant Capacity (MW)
MANITOBA						
Limestone	H		1990	2 x 128	P	
			1991	5 x 128	P	
			1992	3 x 128	P	1 280.00
Wuskwatim	H		1996	87.5	P	
			1997	3 x 87.5	P	350.00
Conawapa	H		1999	130	P	
			2000	4 x 130	P	
			2001	5 x 130	P	1 300.00
SASKATCHEWAN						
Nipawin	H		1985	2 x 84	C	
			1986	84	C	252.00
Meadow Lake	GT	42				42.00
ALBERTA						
Genesee	S(C)		1988	400	C	
			1989	400	C	800.00
Keephills	S(C)	394			I	
			1993	375	P	
			1995	375	P	1 544.00
Sheerness	S(C)		1986	380	C	
			1990	380	C	760.00
Jasper	H		1987	5	P	6.40
Slave River	H		1996	2 x 153	P	-
			1996	3 x 151	P	-
			1997	6 x 151	P	-
			1998	151	P	1 816.00
New Steam	S(C)		1993	375	P	-
			1995	375	P	-
			1996	375	P	
			1997	375	P	
			1999	375	P	
			2000	2 x 375	P	
			2003	375	P	
			2005	375	P	3 375.00

Table A7. Installed generating capacity expansion in Canada by station. Major 1984 additions and projected 1985 - 2004 (Concl'd)

Province and Station	Type*	Additions in 1984 (MW)	Year	Additions Proposed (MW)	Status	Proposed Plant Capacity (MW)
BRITISH COLUMBIA						
Keenleyside	H		2000	2 x 60	P	
			2001	1 x 60	P	210.00
Murphy Creek	H		2002	2 x 55	P	
			2003	3 x 55	P	275.00
Revelstoke	H	3 x 460.75			I	
			1985	460.75	C	1 843.00
YUKON						
Whitehorse system	H	20.0			I	39.39

Legend

H	Hydro	GT	Gas Turbine
S(C)	Steam (Coal)	W	Wind
S(G)	Steam (Gas)	I	Installed
N	Nuclear	C	Under Construction
IC	Internal Combustion	P	Planned

Source: Energy, Mines and Resources - Utility Questionnaire

DEFINITIONS AND ABBREVIATIONS

Alternating Current (a-c): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A co-generating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (d-c): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kWh). The other component of the price is the demand charge.

Firm Power: Electric power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt hour (GWh): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Head: The difference in elevation between the water level immediately above a hydroelectric generating station and the water level immediately below it. (Measured in feet or metres.) The power output of the station is proportional to the head.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 HZ.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy: Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

DEFINITIONS AND ABBREVIATIONS (Cont'd)

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power. 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100 watt light bulbs.

Kilowatt hour (kWh): The commercial unit of electric energy. 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100 watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power. 1000 kilowatts.

Megawatt hour (MWh): A unit of bulk energy. 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

DEFINITIONS AND ABBREVIATIONS (Cont'd)

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: first, in case of unexpected breakdown of generating equipment; second, in case the actual peak load is higher than forecast.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 volts.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

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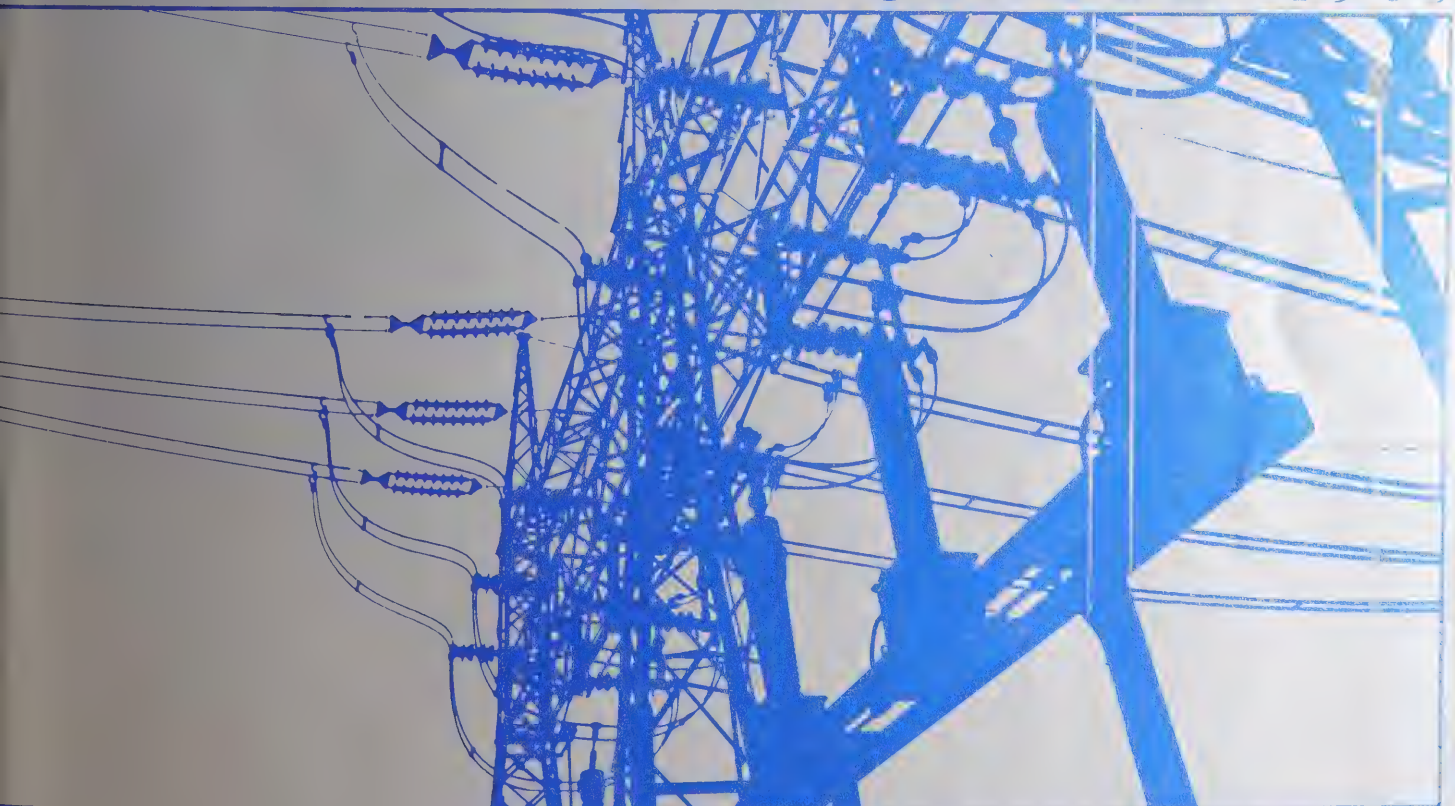
ECTRIC POWER in CANADA 1985



Canada

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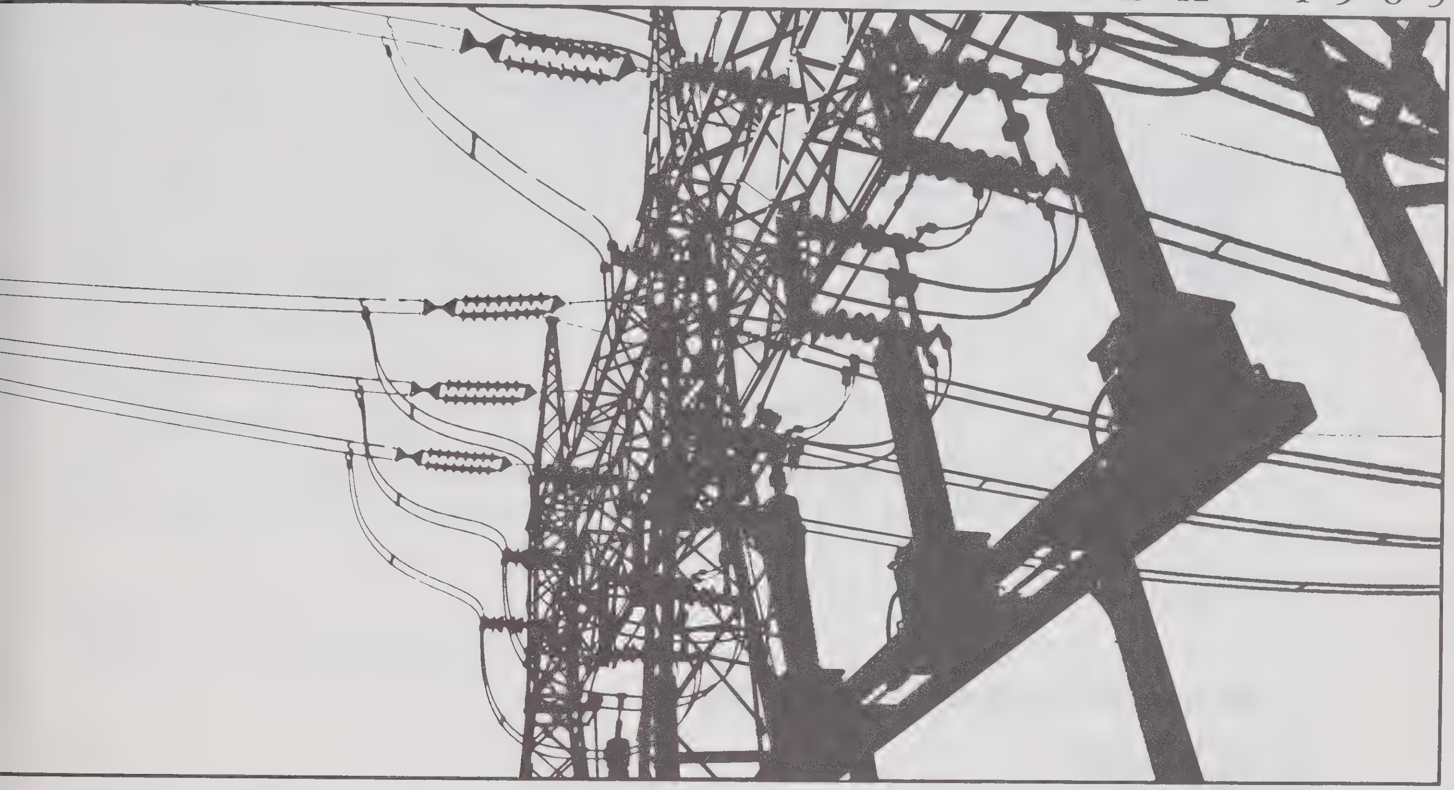

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Tables

Tables (continued)

Figures

The Electric Power Industry in Canada

INDUSTRY STRUCTURE

The electrical industry in Canada is made up of Crown corporations, investor owned utilities, and industrial establishments. In 1985, government owned utilities produced about 85 per cent of total generated electricity, investor owned utilities about 7 per cent, and industrial establishments the remaining 8 per cent. Table 1 shows that over the past 15 years the percentage of energy produced by industrial establishments has decreased, while that of the utilities has increased.

Industrial establishments, which exist in most provinces, generate energy mainly for their own use, although a few sell energy to municipal distribution systems or utilities. About 73 per cent of Canadian industrial establishments with generation facilities are found in Quebec and British Columbia, reflecting the concentration of forest product, mining, and aluminum smelting companies in those two provinces. Over 77 per cent of the electricity generated by industrial establishments is from hydroelectric sources, 11 per cent from natural gas, 4 per cent from oil, and the remainder from other fuels.

Greater public ownership of electric utilities has been the trend in Canada, as provincial governments have taken over most investor owned electric utilities. However, investor owned utilities are still a prominent feature of the Canadian industry. Electricity in Prince Edward Island is supplied by an investor owned utility. In Alberta, two major investor owned utilities supply about 96 per cent of the electricity consumed in the province and municipally owned utilities supply most of the remainder. An investor owned utility distributes 54 per cent of the electricity used in Newfoundland. This utility generates about 9 per cent of its requirements and purchases the remainder mainly from the provincially owned utility. In the Yukon and Northwest Territories, the federally owned Northern Canada Power Commission generates and distributes most of the electricity supplied. Two investor owned utilities supply most of the remainder.

In most provinces, the utilities are fully integrated, from the generation of electricity to its delivery and sale to end users. The principal exception is in Ontario, where about 65 per cent of the total electricity supply is purchased from Ontario Hydro and distributed by more than 300 municipal utilities. In most provinces, electricity is supplied to remote communities by diesel-fired generators or hydroelectric installations which are not tied to the central system.

Unlike investor owned utilities, public utilities do not pay income tax. In order to equalize income tax treatment, 95 per cent of federal income taxes paid by investor owned utilities are refunded to the province of origin under the Public Utilities Income Tax Transfer Act. In the province of Alberta, the tax refund is returned to electricity consumers. In Prince Edward Island, a portion of the tax refund is returned to utility customers. In Newfoundland, the federal tax refund is retained as general revenues of the provincial government.

Table 1. Energy production by utilities and industrial establishments, 1970-1985

Year	Utilities	Industrial Establishments
	(per cent)	
1970	84	16
1975	87	13
1977	88	12
1979	90	10
1981	90	10
1982	90	10
1983	90	10
1984	91	9
1985	92	8

Source: Statistics Canada Publications 57-202, 57-001.

CANADIAN ELECTRIC UTILITIES

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH).

NLPC, an investor owned utility, is the primary retailer of electricity on the island. Approximately 91 per cent of the company's power supply is purchased from NLH, with the balance generated by its own plants. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited, and Union Electric Light and Power Company. Through its predecessors, the company's service dates back to 1885.

NLH is a provincial Crown corporation concerned primarily with electricity generation. It was incorporated in 1975 and is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CF(L)Co), the Lower Churchill Development Corporation (LCDC), Gull Island Power Company, and Twin Falls Power Corporation Limited. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CF(L)Co, NLH owns and operates one of the largest power facilities in the world. On behalf of the province, NLH also administers the activities of the Power Distribution District of Newfoundland and Labrador, which supplies energy to rural customers. Together, NLPC and NLH serve about 200 000 customers.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor owned electric utility which has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission, and distribution of electricity throughout the Island. MECL operates two oil-fired generating plants on the Island at Charlottetown and Borden, which are for stand-by purposes only. It has a 10 per cent equity interest in New Brunswick Electric Power Commission's dual fuel coal/oil fired No. 2 unit located in Dalhousie, N.B., and leases the submarine cable interconnection to New Brunswick owned by the Province of Prince Edward Island. MECL, which serves about 44 100 customers on the Island, currently purchases 98 per cent of its electricity requirements from New Brunswick Power.

A municipal utility in the the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

In 1972, the Nova Scotia Power Corporation bought the shares of the investor owned Nova Scotia Light and Power Co. Ltd. and in 1973 was incorporated as the present Nova Scotia Power Corporation (NSPC) serving all of the province. NSPC generates most of its electricity from thermal energy, with more than half of the production coming from coal. The Corporation also maintains hydro-generation facilities and purchases power from New Brunswick. The largest portion of the total production of the province is derived from the Lingan generating station located on Cape Breton Island. In 1985, NSPC served 348 146 customers.

New Brunswick

Prior to 1918, more than 20 organizations in New Brunswick, both public and private, were in the business of generating and distributing electricity. In 1918, the government of the day passed an Order-in-Council setting up a Water Power Commission to determine the water power resources of the province. Acting on the recommendation of the Commission, the New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. Electricity is generated from a balance of nuclear, hydro, and thermal sources, and the utility also makes purchases from Quebec. NB Power directly provides electricity to 240 797 customers and indirectly serves an additional 37 669 customers through sales to municipal utilities.

Quebec

Hydro-Québec was established by the provincial Legislative Assembly in 1944. After its creation, Hydro-Québec acquired the assets of Montreal Light, Heat and Power Consolidated and Beauharnois Light, Heat and Power Company. In 1963, Hydro-Québec acquired the remaining ten privately owned power companies in the province, including the Shawinigan Water and Power Company, Southern Power Company Limited, Québec Power Company and Gatineau Power Company. Several municipal distribution and public lighting systems were also acquired, together with almost all the electricity cooperatives in Quebec.

Hydro-Québec has two wholly owned, active subsidiaries: the Société d'Energie de la Baie James (SEBJ), which is carrying out the construction of Phase 1 of La Grande Complex; and Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects. Hydro-Québec is also a shareholder in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant, and in Nouveler Inc., which promotes energy efficiency and alternative energy sources. Currently, Hydro-Québec serves more than 2.6 million customers and is responsible for the generation, transmission, and distribution of most of the electricity sold in Quebec. Almost all of the electricity generated by Hydro-Québec is from hydro sources.

Ontario

Ontario Hydro is a Crown corporation, established in 1906 by the Provincial Legislature. It has broad powers to produce, buy, and deliver electric power throughout the province and currently operates under the Power Corporation Act. The main responsibility of Ontario Hydro is to provide power to over 300 municipal utilities, which in turn distribute power to their own customers. In addition, Ontario Hydro supplies about 100 major industrial users directly and about 780 000 rural retail customers in areas or communities not served by municipal utilities. Electricity is generated from a balance of thermal, nuclear, and hydro sources. In 1985, more than three million customers were served by Ontario Hydro and the municipal utilities in the province.

Manitoba

Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the Manitoba Hydro Act. It distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the city owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1985, Manitoba Hydro served about 341 000 customers directly. Almost all of the electricity produced in the province is derived from hydraulic sources.

Saskatchewan

The Saskatchewan Power Corporation (SPC) was established as a Crown corporation under the 1950 Power Corporation Act. It replaced the Saskatchewan Power Commission, created in 1929 to develop an integrated provincial electrical system. Under the Power Corporation Act, the mandate of SPC includes the generation, transmission, and distribution of natural gas and electricity. At the end of 1985, the corporation served about 390 000 customers with electricity and 260 000 customers with natural gas. The bulk of the electricity produced is from thermal sources.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 98 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. Over 80 per cent of the electric energy requirements of Alberta and over half of the population are supplied by the company. In 1985, over 283 000 customers were served directly.

Alberta Power Limited, incorporated in 1972, is another investor owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. Alberta Power supplied about 17 per cent of the total Alberta electricity requirements in 1985, serving over 147 000 customers.

Edmonton Power is Alberta's second largest electric utility and is the largest municipally owned utility in Canada (in terms of generating capacity). Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. The utility produced slightly over seven per cent of the electricity requirements of Alberta in 1985 and served more than 225 000 customers.

British Columbia

British Columbia Hydro & Power Authority (BC Hydro), incorporated in 1961, is a Crown corporation operating in British Columbia. BC Hydro provides electrical service throughout the province, with the exception of the area served by Cominco Limited and its subsidiary, West Kootenay Power and Light Company Limited. BC Hydro is the third largest electric utility in Canada and the largest distributor of natural gas in British Columbia. BC Hydro generates, transmits, and distributes electricity to more than one million customers in a service area which contains more than 90 per cent of the population of the province. It distributes natural gas in Greater Vancouver and in the Fraser Valley, and propane-air gas in Greater Victoria. BC Hydro also operates a local and terminal freight service in Greater Vancouver and the Fraser Valley.

Yukon and Northwest Territories

The Northern Canada Power Commission (NCPC) is a federal Crown corporation, created in 1956, under authority of the Northern Canada Power Commission Act. It is concerned with the planning, construction, and management of utilities on a commercial basis. The Commission is the principal producer of electricity north of 60° latitude and operates the main transmission networks in the north. The NCPC served approximately 12 400 customers in 1985.

Employees of TransAlta Utilities work on the Alberta portion of the 500-kV BC-Alberta intertie, completed in late 1985.

ELECTRIC UTILITIES AND THE ECONOMY

The electric power industry is a significant presence within the Canadian economy. As indicated in Table 2, there were about 75 000 people directly employed by the industry in 1985, or about 0.7 per cent of total Canadian employment.

Total revenue increased to about $15.8 billion in 1985 from $14 billion in 1984, an increase of 13 per cent. Of this total, approximately $1.4 billion or 9 per cent came from export earnings. The electric power industry has steadily increased its contribution to the nation's Gross Domestic Product, from 2.7 per cent in 1980, to 3.2 per cent in 1984, and 3.5 per cent in 1985.

The long-term debt for the Canadian electric power industry was $62 billion in 1985, with 82 per cent of this debt owned by Ontario Hydro (36 per cent), Hydro-Québec (33 per cent), and BC Hydro (13 per cent).

Total assets of the industry were about $87 billion in 1985. Ontario Hydro, Hydro-Québec, and BC Hydro are the three largest electric utilities in Canada and rank first, second, and fifth respectively, in terms of assets among all Canadian companies.

Table 2. Electric utility assets, debt, revenue and employees, 1985

	Assets	Debt	Revenues	Employees
	($ millions)			
Nfld.	2 457	1 532	575	2 134
P.E.I.	86	27	64	201
N.S.	1 413	1 172	492	2 450
N.B.	2 870	2 163	894	2 500
Que.	29 183	20 123	4 492	18 208
Ont.	29 320	22 518	4 625	31 166
Man.	3 129	2 524	553	3 853
Sask.	2 150	1 778	470	3 064
Alta.	5 561	1 758	1 423	4 687
B.C.	10 472	8 209	2 094	6 508
NWT/Yuk.	276	235	89	330
Canada	86 917	62 039	15 771	75 101

Source: Electric Utilities' Annual Reports.

Canadian Electricity in the International Context

The purpose of this chapter is to compare Canada's electric power industry with those from other selected western industrialized countries.

TOTAL INSTALLED GENERATING CAPACITY

As of December 31, 1984, the United States' total generating capacity was the largest in the world at 672 GW. Of this total, about 77 per cent was conventional thermal, with almost half supplied by coal-fired stations. Japan ranked second among western countries, with installed capacity of 163 GW. A large proportion of Japan's total installed capacity was also conventional thermal (about 67 per cent), with half of this total coming from oil-fired stations. Canada ranked third in terms of overall installed capacity. Canada's hydro generating capacity, at 57 per cent of the national total, made it the largest proportionate user of hydroelectricity in the western world.

At the end of 1984, the United States had the largest nuclear capacity in the world, with a total of 72 GW. As a percentage, however, France's nuclear capacity was the largest, accounting for 39 per cent of its total. Canada ranked fifth in terms of installed nuclear capacity. Table 3 indicates total installed generating capacity in 1984 for selected Organization for Economic Co-operation and Development (OECD) countries.

Table 3. Total installed generating capacity in major industrialized countries, at December 31, 1984 (MW)

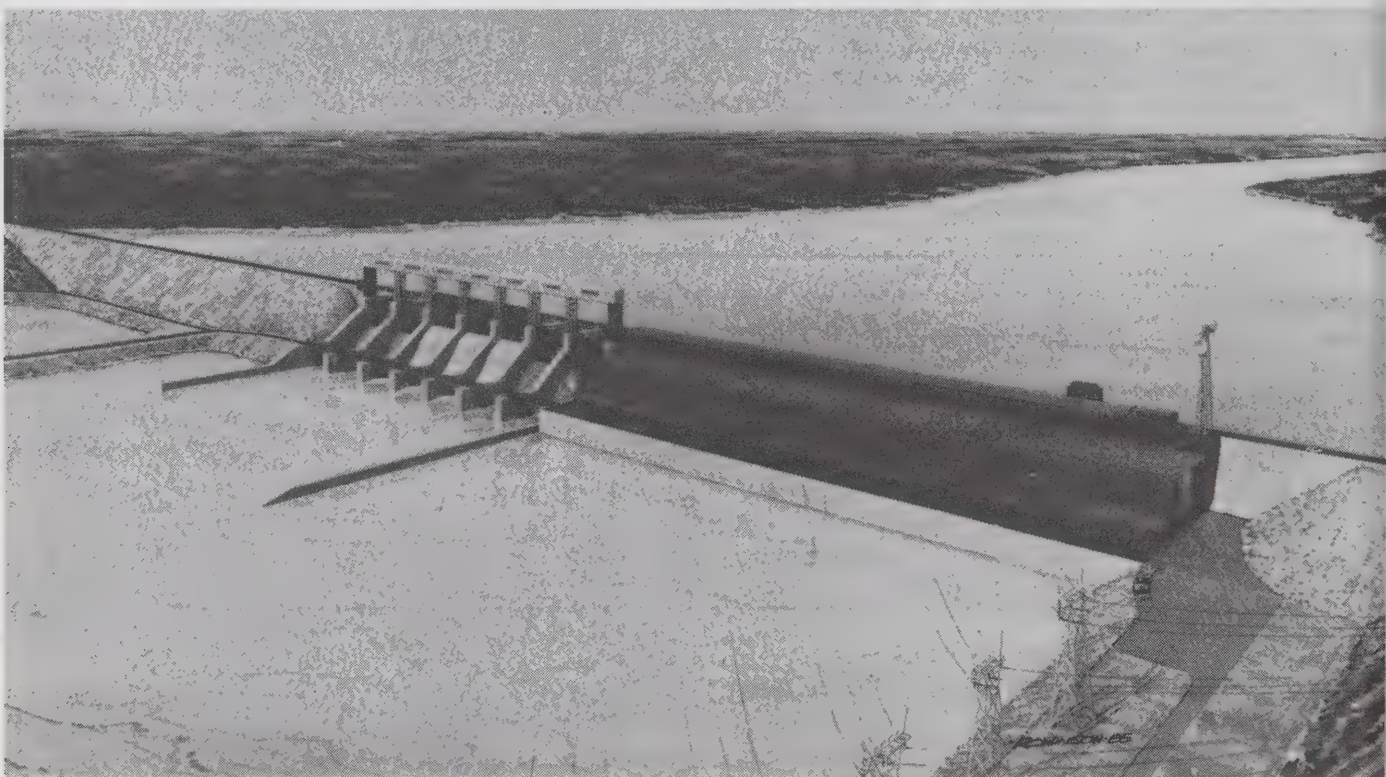
Country	Conventional Thermal	Hydro	Nuclear	Total
United States	518 030	81 802	71 861	671 693
Japan	108 632	33 964	20 726	163 322
Canada	31 068	54 876	9 587	95 531
West Germany	68 398	6 630	14 838	89 866
France	30 298	21 435	32 947	84 680
Great Britain	56 162	4 190	6 550	66 902
Italy	35 374	17 343	1 273	53 990
Netherlands	16 068	0	508	16 576
Belgium	7 519	1 325	3 465	12 309

Source: Electrical Energy Branch
Energy, Mines and Resources Canada.

Table 4. Electricity generation sources in major industrialized countries, 1985 (TWh)

Country	Conventional Thermal	Hydro	Nuclear	Total
United States	1 827	285	387	2 499
Japan	454	81	142	677
Canada	88	301	57	446
West Germany	265	18	126	409
France	56	64	224	344
Great Britain	230	7	60	297
Italy	134	45	7	186
Netherlands	59	0	4	63
Belgium	21	1	35	57

Source: Electrical Energy Branch, Energy, Mines and Resources Canada.



An artist's conception of the 1200-MW Limestone generating station, now under construction on the Nelson River in northern Manitoba. The station is due to be completed in 1990.

TOTAL ELECTRICITY GENERATION

In 1985, the United States generated about 2499 TWh of electricity. Of this total, 57 per cent came from coal-fired stations, 16 per cent from nuclear, 12 per cent from natural gas, 11 per cent from hydro, and the remaining 4 per cent from oil.

Canada's hydro generation was the largest among western industrialized countries in 1985, in both quantity and percentage. Canada's hydro stations generated 301 TWh of electricity, about 67 per cent of the total.

French electricity sources were highly dependent on nuclear energy; in 1985, about 65 per cent of total electricity generation came from nuclear stations. Belgium also had a high nuclear proportion, with 61 per cent. West Germany's nuclear generation accounted for 31 per cent of its total production, while in Japan and Great Britain, the nuclear share was about 20 per cent. Although the United States had the largest absolute volume of nuclear energy generation in 1985, it only accounted for 15 per cent of the country's total production. Canada's nuclear production, as a share of total production, was a relatively small 13 per cent in 1985. Table 4 reports electricity generation sources in selected OECD countries for 1985.

DOMESTIC ELECTRICITY CONSUMPTION

Between 1975 and 1985, Canada consumed more electricity per capita than any other major industrialized country in the world. Table 5 indicates that Canada consumed on a per capita basis almost twice as much electricity as the United States in 1985, and about five times that of Italy. During the past 10 years, per capita electricity consumption for Canada grew at an average of 4.2 per cent, second only to France's 5.0 per cent.

A number of factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economic hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led many electricity intensive industries to locate in Canada. As well, energy consumers generally tend to use more electricity when its price is relatively low. For example, Canada's consumers paid an average price of 3.09 US cents per kWh in 1984, compared with France's 4.77, USA's 6.52, West Germany's 6.28, and Japan's 9.92. Finally, Canada's northerly location means a long and cold winter season, resulting in much energy being used for space heating purposes.

ELECTRICITY INTENSITIES

Table 6 compares the intensity of electricity use in the economies of selected industrialized countries. Electricity intensity is defined as total electricity consumption per dollar of GDP. To facilitate the comparison, all currencies were converted into United States dollars at 1980 prices and exchange rates. The data indicates that Canada has the highest electricity intensity and that electricity intensities in Canada, France, West Germany, and Belgium have been increasing since 1975. In Japan and Great Britain, there have been clear-cut reductions in electricity intensities. Electricity intensity in the United States appears to have reached its peak in 1980 and declined slightly since then. Italy and the Netherlands increased their electricity intensities from 1975 to 1980 and then stabilized.

Table 5. Total domestic electricity consumption per capita in major industrialized countries (kWh/person)

Country	1975	1980	1985
Canada	11 702	15 260	17 590
United States	8 089	9 194	9 651
West Germany	5 008	6 083	6 736
France	3 577	4 847	5 817
Belgium	4 106	5 180	5 812
Great Britain	4 837	5 060	5 252
Japan	3 831	4 449	4 963
Netherlands	3 951	4 558	4 699
Italy	2 704	3 400	3 670

Source: Electrical Energy Branch Energy, Mines and Resources Canada.

Table 6. Electricity consumption per unit of GDP in major industrialized countries (kWh/US$1980)

Country	1975	1980	1985
Canada	1.24	1.41	1.53
United States	0.87	0.88	0.85
Japan	0.57	0.55	0.52
Great Britain	0.55	0.53	0.51
France	0.33	0.39	0.50
West Germany	0.44	0.45	0.48
Belgium	0.40	0.46	0.47
Italy	0.45	0.47	0.45
Netherlands	0.36	0.38	0.36

Source: Electrical Energy Branch Energy, Mines and Resources Canada.

The Regulatory Environment

FEDERAL REGULATION

Constitutional Authority

Under the Canadian Constitution, legislative authority for electricity generation, transmission and distribution rests primarily with the provinces. Federal authority regarding electricity is restricted to exports, nuclear energy, and international and designated interprovincial power lines. Provincial ownership of most energy resources stems from Section 109 of the Constitution Act, which in turn is supplemented by section 92A of the Act, giving provincial legislatures authority over the development, conservation, and management of sites and facilities in the province for the generation and production of electrical energy. Federal responsibility for all aspects of nuclear energy, including uranium production and supply, was formalized with the Atomic Energy Control Act of 1946.

National Energy Board

The National Energy Board (NEB) was created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the National Energy Board Act. Under the Act, the Board advises the federal government on the development and use of energy resources and regulates specific matters concerning oil, gas, and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. (Under Part VII of the Act, the Governor in Council may by order designate a particular interprovincial power line to be regulated in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.) The Board has no jurisdiction over imports of electricity.

Part III of the NEB Act provides for the federal regulation of international and designated interprovincial power lines. The Board may authorize, without a public hearing, the construction and operation of international power lines not exceeding 50 kV. When reviewing an application for an international power line, the Board determines whether the line is in the public interest by assessing i) the availability of electricity for export, ii) the existence of markets, iii) economic feasibility, iv) financing considerations and Canadian participation, and v) any other consideration that may be relevant. In making this determination, the Board holds public hearings. If positive, the Board's decision is submitted to the Governor in Council; if negative, the application is rejected.

Part VI of the NEB Act provides for the regulation of electric power exports. The Board issues export licences in which it imposes terms and conditions on the licensees. The Act restricts the duration of licences to 25 years. In considering an export application, the Board is required to take into account all factors pertaining to the public interest. In particular, the Board must satisfy itself that i) the quantity of electricity to be exported is surplus to reasonably foreseeable domestic requirements, and ii) the price is just and reasonable.

In interpreting the latter requirement the Board has established three guidelines concerning the export price: i) it must recover its appropriate share of the costs incurred in Canada; ii) it must not be less than the price to Canadians for equivalent service in related areas; and iii) it must not be materially less than the least-cost alternative available to the foreign purchaser at the same location in the country of export.

Before licensing exports, the Board normally conducts a public hearing. However, when the export quantities are small (i.e., not more than 50 MW and 250 GWh/year), or when emergency conditions exist, the Board may issue "orders", authorizing exports without public hearings.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes while at the same time preventing its use for weapons. In 1946, the Atomic Energy Control Act was passed into law with these objectives in mind.

The Act gave the federal government control over the development, application and use of nucler energy and established the Atomic Energy Control Board (AECB). The five-person AECB administers and enforces the Act, and licenses uses of radioactive materials and activities involving nuclear energy. It also regulates the health, safety, security and environmental aspects of nuclear energy. The AECB reports to Parliament through the Minister of Energy, Mines and Resources.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities, and particle accelerators. Prescribed substances include uranium, thorium, heavy water, and radioisotopes. Activities that may be licensed, relating to such substances, include production, processing, selling, use, import, and export. Before issuing a licence, the Board ensures that the appropriate health, safety and security standards are met.

The Board's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

Federal Environmental Assessment Review Process

In December 1973, Cabinet established the Federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal projects are assessed early in the planning process. A federal project is one initiated by a federal agency, or one that involves federal funding or federal property. Federal Crown corporations are not bound by the Cabinet decision; however, they are invited to participate in the process.

In 1977 and 1979, the process was modified. In June 1984, an Order-in-Council further strengthened EARP and formalized a number of functions.

Under EARP, federal departments are responsible for assessing their own projects. They conduct an initial screening to determine whether a given project will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department.

If significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the project sponsor prepare an Environmental Impact Statement. If the Minister of the Environment and the initiating Minister concur, the scope of the Panel may be extended to include general socio-economic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the project is provided with an opportunity to present viewpoints to the panel.

Once a panel has completed its deliberations and evaluated all information on a project, it prepares a report outlining, among other things, its recommendations. A Panel could recommend that a project not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating Minister, who must decide to whom the recommendations are directed, to what extent they should be incorporated into terms and conditions for proceeding, and in what manner they are to be made public. In the event of a disagreement between the two Ministers, the question may be submitted to Cabinet.

PROVINCIAL REGULATION

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission, and distribution of electricity. In most provinces some form of regulation exists to ensure that power is supplied at the lowest possible rate compatible with sound financial management. Most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate setting and the construction of new facilities. All provinces require the environmental effects of proposed projects to be studied.

Newfoundland

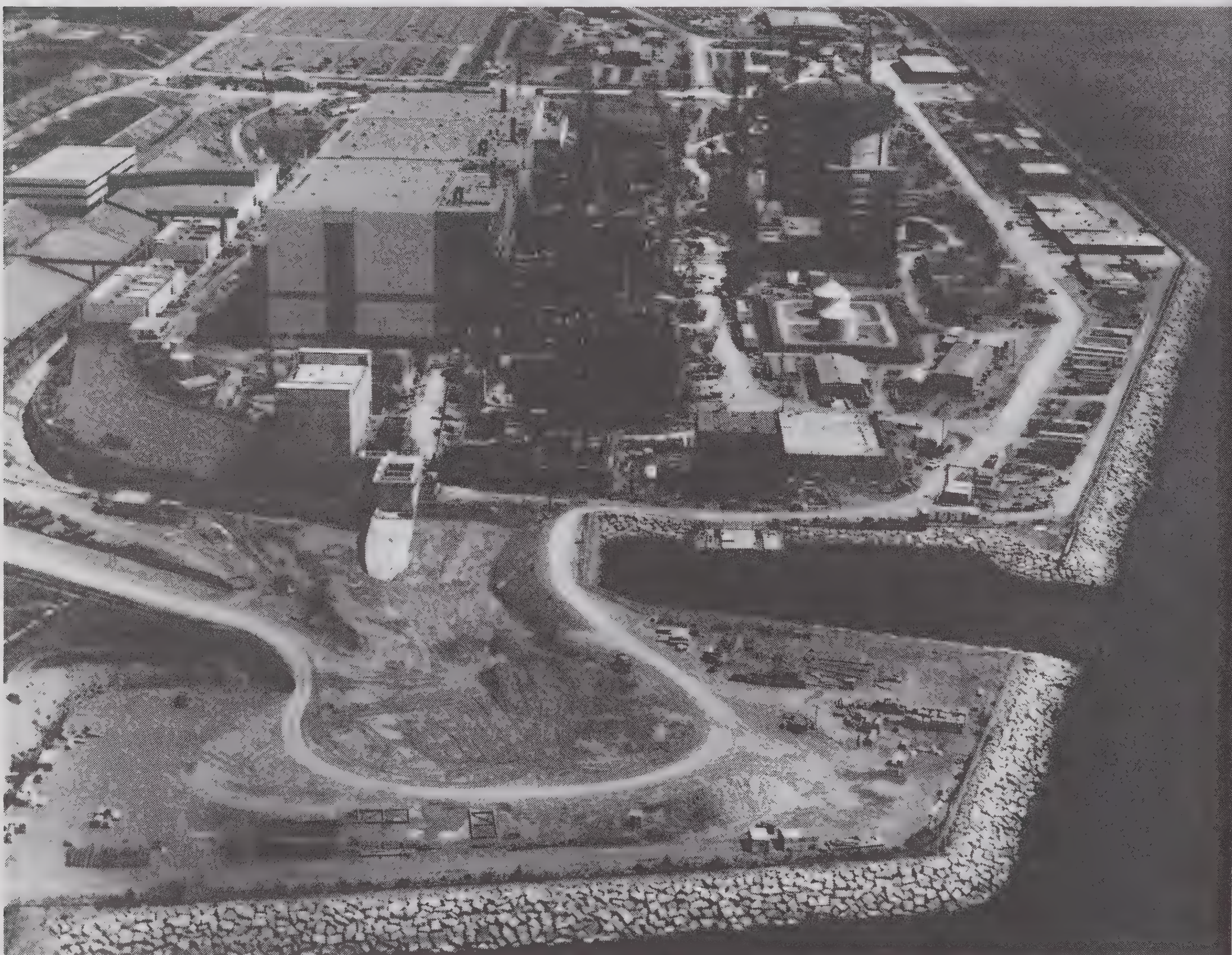
Newfoundland Light and Power Company (NLPC) and Newfoundland Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC. Since 1977, the Board has also had authority under the Electric Power Control Act to review NLH's utility rates, excluding sales to subsidiaries and industrial customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision making authority over electric utility rates in the province.

Nova Scotia

Prior to 1976, the Nova Scotia government directly set rates and policies for electric utilities in the province. Since that time, the Board of Commissioners of Public Utilities has taken over this duty and, in accordance with the provincial Public Utilities Act, has full decision making power.



Ontario Hydro's busiest construction site in 1985 was the four unit Darlington nuclear generating station, east of Toronto. The 3600-MW station is expected to be fully operational in 1992.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

Quebec

In Quebec, electricity rates are set by Hydro-Québec and are subject to the approval of the provincial legislative assembly. Hydro-Québec operations are administered by a seventeen-member Board of Directors, which includes the President and Chief Executive Officer.

Ontario

Ontario Hydro operates under the Power Corporation Act and reports to the provincial government through the Ministry of Energy. The management of Ontario Hydro is under the direction and control of the Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, the Board of Ontario Hydro is authorized to set the utility's rates and may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board.

Manitoba

Under the Manitoba Hydro Act, rates are set by Manitoba Hydro and reviewed by the Public Utilities Board. The Board provides advice to the provincial government, leaving the Lieutenant Governor in Council with final authority over pricing and other matters related to the supply of electricity.

Saskatchewan

Saskatchewan Power Corporation (SPC) is governed by a Board of Directors that is responsible for the management and operation of the Crown utility. Board members are appointed by the provincial government and report to the province's Crown Management Board. Rates charged to SPC's electricity customers are subject to review and approval by the Public Utilities Review Commission of Saskatchewan.

Alberta

TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power are regulated by the Energy Resources Conservation Board, with respect to the development of generation and transmission facilities and changes in service areas. Environmental and social impact assessments and plans to minimize any environmental impacts must be presented to the Board along with applications for construction. The Board's recommendations on generating plants are subject to final approval through Order-in-Council by the Alberta government.

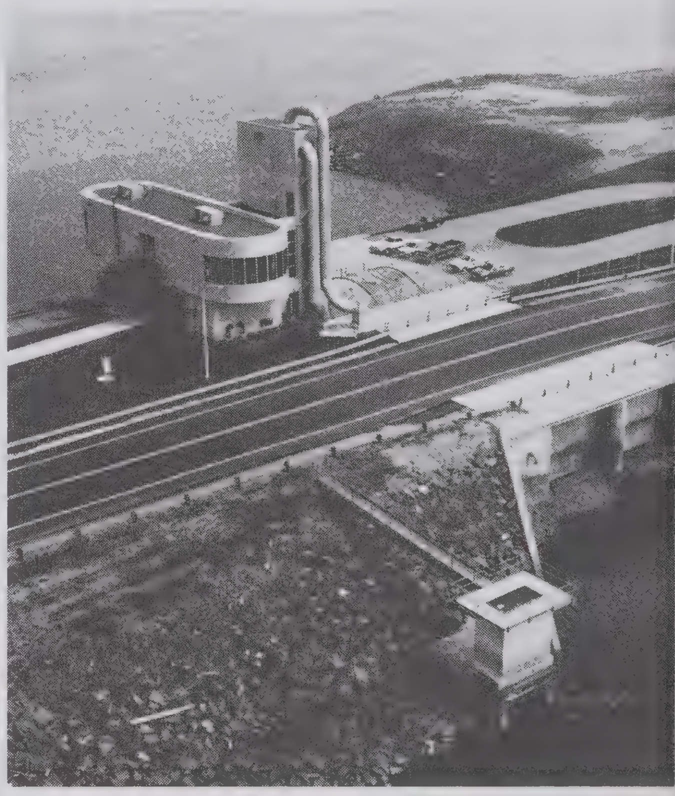
The three utilities participate in the cost pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA. The EEMA pools the utilities' costs and resells the power at average prices back to the utilities.

British Columbia

The British Columbia Utilities Commission (BCUC) has general supervisory powers over BC Hydro. Jurisdiction extends to system expansion, operation, financial transactions, and rate schedules. Cominco Limited, which operates generating plants and transmission facilities for industrial purposes, is exempt from regulation by the BCUC. Under a management contract, West Kootenay Power & Light Co. operates and maintains Cominco's facilities. West Kootenay's operations for its direct customers are subject to regulation by the BCUC. New electricity exports require removal permits granted by the BCUC, after authorization by the Lieutenant Governor in Council.

Yukon and Northwest Territories

Under the Northern Canada Power Commission Act, the Commission is to be self-sustaining within the rate zones of the Yukon and Northwest Territories. To ensure this, rates charged by utilities must provide sufficient revenue to cover principal and interest charges on federal loans to the Commission and operating costs of the Commission.



The 20-MW Annapolis tidal power plant in Nova Scotia is the first of its kind in North America.

Consumption and Generation

ELECTRICITY CONSUMPTION IN 1985

After an increase of 7.1 per cent in 1984, electricity demand in Canada experienced another strong increase in 1985, with a growth rate of 5.3 per cent. As in 1984, this increase was related to economic activity. Real Gross Domestic Product (GDP), with which electricity demand is historically correlated, grew 4.5 per cent in 1985, the second highest annual increase since 1977 and only slightly less than the 4.8 per cent increase of 1984.

Other factors contributing to the growth in electricity consumption include a relatively cold winter and the recent trend from oil to electric space heating. The off-oil move was partly stimulated by a federal program under which eligible consumers received taxable grants to offset conversion costs. Over the period October 1980 to March 1985, approximately 988 000 households converted from oil to alternative energy sources. The largest share of these conversions, 45 per cent, was from oil to electricity.

Because of the strong increase in electricity demand, the relative importance of electricity in the Canadian economy continued to increase in 1985. The quantity of electricity consumed, expressed in kilowatt-hours per dollar of real GDP (1971$), was 3.12 in 1985, up from 3.09 in 1984, 2.89 in 1980, 2.65 in 1975, and 2.58 in 1970. This represents an increase of about 21 per cent during the period 1970-1985.

Table 7 shows the 1985 growth rates in electricity demand by province and the major utilities. Growth rates varied considerably by province, from a high of 7.4 per cent for British Columbia to a low of 1.0 per cent for New Brunswick. Of the major utilities, Hydro-Québec, for the second consecutive year, experienced the largest growth rate at 9.4 per cent, followed by BC Hydro with 8.1 per cent.

In British Columbia, an increase in industrial load accounted for most of the 7.4 per cent growth in electricity demand in 1985. The pulp and paper industry returned to full capacity operation after a long strike came to an end in April, and the lumber industry was also in full production. Both industries use large quantities of electricity. In Quebec, successful marketing programs by Hydro-Québec, which hastened oil-heating system conversions and increased consumption of electricity in the industrial sector, contributed to that province's high growth in electricity demand. Of the 403 351 conversions from oil in Quebec between October 1980 and March 1985, about 78 per cent were conversions to electricity.

Electricity consumption and generation, by province, is given in Table 8. The table also indicates international and interprovincial trade flows, thus accounting for the difference between each province's production and consumption. Quebec was the largest producing and consuming province in 1985, while British Columbia was the largest in terms of international exports.

Table 7. Percentage growth in electricity demand, 1985

	Province	Major Utilities
Newfoundland	3.1	5.4
Prince Edward Island	6.5	6.5
Nova Scotia	5.8	4.9
New Brunswick	1.0	3.1
Quebec	6.9	9.4
Ontario	3.4	3.3
Manitoba	4.2	3.3
Saskatchewan	2.0	2.2
Alberta	7.0	6.5
British Columbia	7.4	8.1
Yukon/NWT	2.5	0.4
Canada	5.3	6.1

Source: Energy, Mines and Resources Canada.

Electricity demand by sector for the period 1980-85 is reported in Table 9. The industrial sector consumes the largest share of electricity. During the period 1980-85 it consistently accounted for 51 per cent of total consumption, followed by the residential sector with 25 per cent, the commercial sector with 22 per cent, and the agricultural sector with the remaining 2 per cent.

FORECAST DEMAND

The demand for electricity is affected by many factors: economic activity, demographic activity, electricity prices, other energy prices, energy policy, and weather. Economic activity is the most important variable and has been traditionally used by electric utilities as the key factor to predict aggregate demand for electricity.

Figure 1 shows the close historical relationship between per capita economic performance, as measured by GDP, and per capita electricity demand. Although the historical relationship between national economic growth and electricity demand was dislocated during the period 1979-83, the historical trend appears back on track since 1984.

Table 10 shows the growth, over the period 1960-1985, of real GDP, population, primary energy demand, and electrical energy demand. Table 10 also presents the forecasts prepared by Energy, Mines and Resources Canada (EMR), for each of these variables for the period 1985-2000.

Newfoundland Light and Power Company helped mark its centenary in 1985 by turning the Victoria hydro plant into a museum, displaying a turn-of-the-century turbine.

Table 8. Provincial electricity consumption, 1985 (GWh)

Province	Production	Exports to Provinces	Exports to U.S.	Imports	Consumption
Newfoundland	41 387	31 837	-	-	9 550
Prince Edward Island	2	-	-	575	577
Nova Scotia	7 511	199	-	350	7 662
New Brunswick	11 422	927	6 093	6 038	10 440
Quebec	136 727	14 491	9 581	31 881	144 536
Ontario	121 661	44	10 563	11 333	122 387
Manitoba	22 742	2 524	5 660	1 283	15 841
Saskatchewan	11 816	1 236	163	1 649	12 066
Alberta	33 253	243	-	280	33 290
British Columbia	59 126	275	10 956	1 080	48 975
Yukon/NWT	766	-	-	-	766
Canada	446 413	51 776	43 016	54 469	406 090

Source: Electrical Energy Branch, Energy, Mines and Resources Canada.

Table 9. Total electricity demand in Canada by sector, 1980-1985

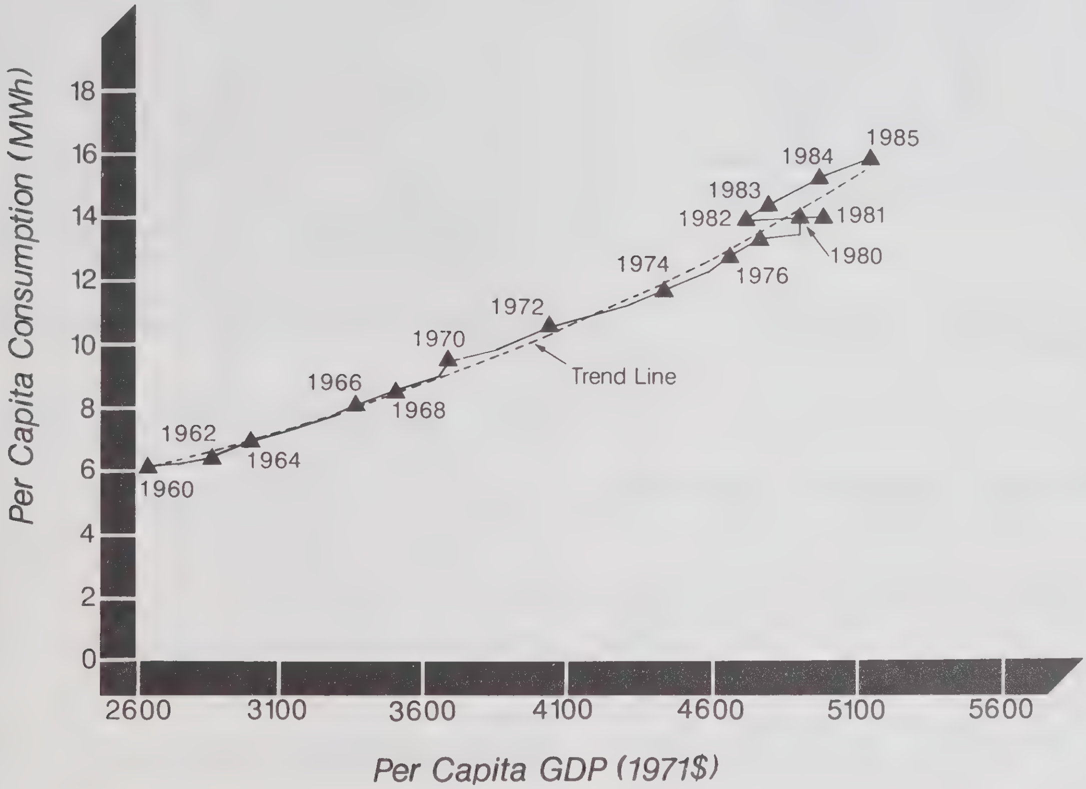
	1980		1981		1982		1983		1984		1985	
	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%	TWh	%
Residential	85.6	25	86.9	25	87.5	25	90.4	25	97.3	25	102.4	25
Farm	7.9	2	8.0	2	8.0	2	8.3	2	8.9	2	9.4	2
Commercial	74.2	22	75.4	22	75.4	22	78.6	22	84.3	22	88.7	22
Industrial	171.7	51	174.3	51	174.2	51	182.5	51	195.0	51	205.5	51
Total	339.4	100	344.6	100	345.1	100	359.8	100	385.5	100	406.1	100

Source: Energy Information Handbook, Energy, Mines and Resources Canada, April 1986.

Figure 1

Historical Relationship between Electricity Demand and GDP

1960–1985



Because economic growth and population growth over the next 15 years are expected to be significantly lower than the previous 26-year period, electricity growth is also expected to be lower. However, the forecast data presented in Table 10 also indicates an increasing role for electrical energy in Canada. The percentage of primary energy supplied in the form of electricity is expected to increase from 43 per cent in 1985 to about 44 per cent in 1990 and 46 per cent in the year 2000.

Table 10. Historical and forecast annual growth rates (per cent)

	1960-85	1974-85	1985-2000
Real GDP	4.2	2.5	2.5
Population	1.4	1.2	0.6
Primary Energy	3.6	1.3	2.5
Electrical Energy	5.4	3.9	2.9

Source: Energy, Mines and Resources Canada.

Table 11 summarizes electricity demand forecasts prepared by the major utilities and provided to EMR in January 1986. The extent of the changed perception of future demand is illustrated in the forecasts provided in January 1985, shown in brackets. With the exceptions of Newfoundland, Nova Scotia, Manitoba, and Alberta, all electric utilities increased their forecast demand growth over the period 1985-2000 from the forecasts provided in January 1985.

Table 11. Utility forecasts of electricity demand (per cent) as at January 1986*

	1985-1990	1990-2000	1985-2000
Nfld.	2.2 (2.8)	2.5 (2.9)	2.4 (2.9)
P.E.I.	3.4 (3.2)	2.7 (2.7)	3.0 (2.9)
N.S.	3.3 (4.0)	3.8 (3.7)	3.6 (3.8)
N.B.	4.2 (3.1)	2.2 (2.3)	2.8 (2.5)
Que.	1.8 (1.2)	1.8 (2.0)	1.8 (1.7)
Ont.	3.6 (2.4)	2.1 (2.3)	2.6 (2.3)
Man.	2.6 (3.2)	2.0 (2.5)	2.2 (2.7)
Sask.	3.3 (2.2)	2.0 (2.2)	2.4 (2.2)
Alta.	4.2 (4.1)	3.0 (3.6)	3.4 (3.8)
B.C.	1.7 (2.0)	1.9 (1.4)	1.9 (1.6)
NWT/ Yuk.	-0.5 (0.8)	0.8 (0.5)	0.4 (0.6)
Canada	2.7 (2.1)	2.1 (2.2)	2.3 (2.2)

* Figures in brackets are January 1985 estimates.

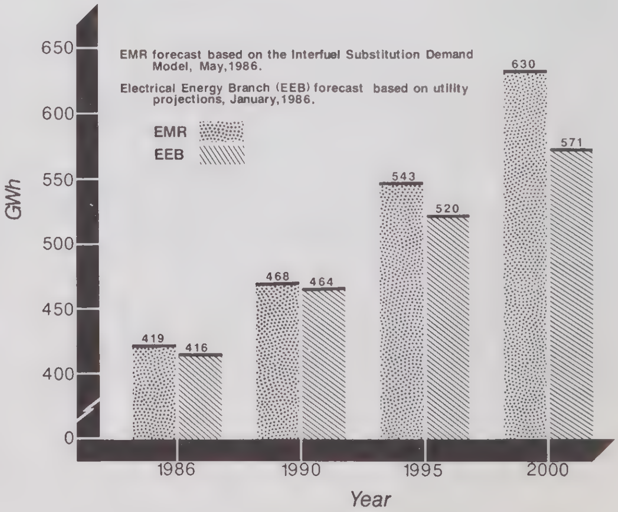
Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Because of the difficulty in forecasting electricity demand with a high degree of certainty, most utilities are now considering a range of demand forecasts with an assignment of statistical probability to each. As well, they are adopting an approach to planning which emphasizes flexibility. Rather than plan generating capacity solely to meet whatever demand develops, they are taking steps to alter peak demand requirements by means such as direct load management, while simultaneously ensuring that generating capacity is sufficient to meet demand under reasonable assumptions regarding future growth.

Figure 2 illustrates various forecasts for electricity demand. Included on the bar chart for comparison are the latest forecasts derived from EMR's Interfuel Substitution Demand Model and the forecast developed by the EMR Electrical Energy Branch on the basis of projections provided by the major utilities.

Figure 2

Electrical Energy Forecasts



PEAK DEMAND

Peak demand in Canada grew by 4.8 per cent in 1985, up from 69 044 MW in 1984 to about 72 367 MW in 1985. This increase is much greater than the 3.6 per cent registered in 1984. Based on the electric utilities' projections, peak demand is expected to increase annually by 2.4 per cent, to 104 000 MW by the year 2000. This growth rate is slightly larger than the 2.1 per cent projected last year. For overall energy and peak demand forecasts, the electric utilities have increased their projections this year, reflecting confidence about future load growth. Table 12 reports the forecast peak demand growth rates for all provinces and territories, as projected by the major electric utilities for the period 1985-2000.

LOAD FACTOR

As was pointed out earlier, energy demand grew faster than peak demand in 1985. The growth rate was 5.3 per cent for energy compared with 4.8 per cent for peak. Load factor for Canada as a whole increased by 0.6 per cent, from 63.7 per cent in 1984 to 64.1 per cent in 1985. Load factors for each province and Canada during the period 1985-2000 are reported in Table 13. (Load factor is defined as a ratio of average demand to peak demand, where average demand = energy consumption/8700 (hrs/yr).)

Table 12. Peak demand growth rates (per cent)

	1985-1990	1990-2000	1985-2000
Nfld.	2.7	2.8	2.8
P.E.I.	3.4	2.7	2.9
N.S.	4.2	3.7	3.9
N.B.	4.7	2.2	3.0
Que.	2.7	2.1	2.3
Ont.	1.6	2.4	2.2
Man.	3.4	2.0	2.5
Sask.	3.7	2.0	2.6
Alta.	3.8	2.8	3.1
B.C.	2.3	1.9	2.0
NWT/Yuk.	1.1	0.8	0.9
Canada	2.6	2.3	2.4

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 13. Load Factor in Canada (per cent)

	1985	1990	2000
Nfld.	62.8	61.2	59.3
P.E.I.	60.3	60.4	60.5
N.S.	63.9	61.0	61.1
N.B.	61.0	59.6	59.6
Que.	62.7	59.9	58.1
Ont.	64.6	71.3	68.6
Man.	59.4	57.2	56.9
Sask.	61.0	59.6	60.0
Alta.	69.7	70.9	72.1
B.C.	67.2	65.2	65.5
NWT/Yuk.	56.8	52.3	52.4
Canada	64.1	64.5	63.0

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

ENERGY GENERATION

Electricity generation increased 5.1 per cent in 1985 to 446 TWh. Of this, 406 TWh was for use in Canada and the remainder was exported. The sources of generation are given in Table 14. The major generating stations in Canada are shown in Figure 3.

Table 14. Source of electricity production

Generation Type	% of 1985 Generation	% Increase from 1984
Hydro	67	6.2
Thermal	20	-3.9
Nuclear	13	15.9

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

The increased hydro generation was mainly attributable to new production from James Bay in Quebec (14 000 GWh) and Revelstoke in British Columbia (3000 GWh). Electricity production from fossil fuels decreased by 3.9 per cent in 1985 over 1984. The fossil fuel share of total electricity production was 20 per cent, a reduction of 2 per cent from the previous year. The production of electricity from coal decreased by 7 per cent because of the reduction of coal-fired generation in Ontario. However, generation from oil increased by 14 per cent mainly due to Newfoundland's increase in oil-fired generation.

Generation from natural gas increased by 30 per cent. The increase was attributed to industrial use of gas in Alberta. Total nuclear production increased by 15.9 per cent, mainly from new production at the Pickering B7 and Bruce B5 stations, which were commissioned in January 1985 and March 1985, respectively.

Figure 4 and Table A4 show energy production by fuel type. Production by region and energy source is shown in Figure 5. The major increases in coal-fired production were in Nova Scotia (13 per cent), and Saskatchewan (2 per cent). Coal-fired production declined by 21 per cent in New Brunswick and 19 per cent in Ontario. In Alberta, British Columbia, and Ontario, natural gas is mainly used by industries for electricity generation. Natural gas-fired production declined by 77 per cent in British Columbia, while increasing 140 per cent in Alberta, and 46 per cent in Ontario. See Chapter 6 for details on the fuel requirements of these provinces.

Oil-fired production increased in Newfoundland as a result of decreased hydro generation on the Island. In Nova Scotia oil-fired production decreased as a result of displacement by coal-fired production. New Brunswick maintained a high level of oil-fired production because of its export commitment; it is estimated that about 60 per cent of its electricity generated from oil was exported to the U.S.

Figure 3

Major Generating Stations in Canada (MW)

Figure 4

Energy Generation by Principal Fuel Type

1985 % of Provincial Total

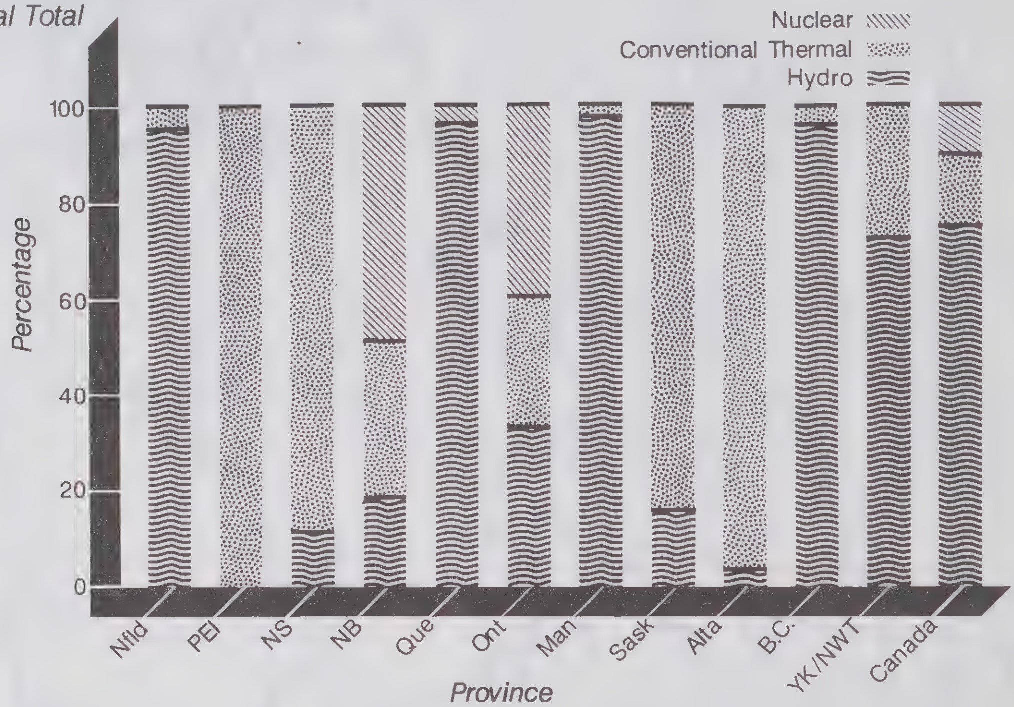
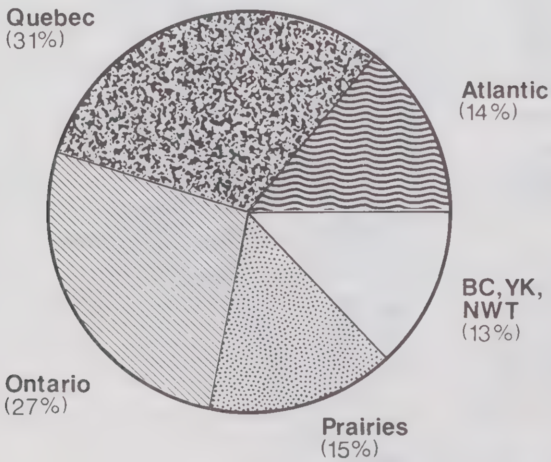
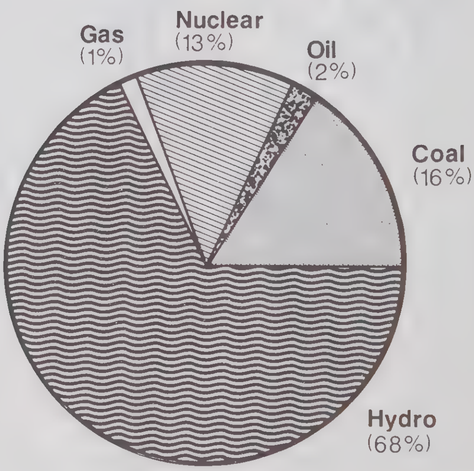


Figure 5

Production by Region and Production by Energy Source

1985





Total: 446 413 GWh

Nuclear generation was 13 per cent of the total in 1985. In Quebec, the Gentilly II station decreased its generation slightly from 3422 GWh in 1984 to 3209 GWh in 1985. In Ontario, two new nuclear units were put in service, and the remaining increase for the year came from increased production in New Brunswick. Nuclear generation increased by about 16 per cent, from 49 266 GWh in 1984 to 57 095 GWh in 1985. The Point Lepreau station also increased its production from 5011 GWh in 1984 to 5427 GWh in 1985; of the total, about 37 per cent was produced for firm exports to the United States.

FORECAST OF ENERGY GENERATION

Utility forecasts of electricity generation, by principal fuel type for Canada, are presented in Table 15. The data suggests that hydro-based generation will continue to be the most important source of electric energy in Canada, although its share of total electricity production will decline slightly from about 67 per cent in 1986 to about 60 per cent in 2000. Coal-fired production is expected to decrease, in both quantity and market share, between 1985 and 1990, and then steadily increase to 18 per cent of total electricity generation by the year 2000. The main reason for the 1985-90 decrease is Ontario Hydro's plan to reduce its coal-fired generation from 30 TWh in 1985 to only 15 TWh by 1990. This substantial reduction will be offset by increasing nuclear production from the Darlington nuclear stations.

Although the recent falling world oil prices provide electric utilities with an economic incentive to utilize their existing oil-fired stations in the short-run, it is not expected that oil prices will remain low for a long period of time. In the long run, oil-fired stations will continue to be used as peaking capacity and to serve energy demand in remote locations. Beyond 1990, the use of oil in electricity generation is expected to increase with the overall increase in demand. By the year 2000, the share of electricity generated from oil is expected to reach 2 per cent of total electricity generation. Natural gas will continue to be used sparingly, accounting for only about 1 per cent of total electricity generation by the year 2000.

Nuclear generation is forecast to increase at an average annual rate of 3.2 per cent between 1986 and the year 2000. Its share of electricity generation is expected to increase from 15 per cent to about 18 per cent over the same period.

Table 15. Forecasts of energy generation by fuel type - Canada

	Energy Generation (TWh)							Percentage of Generation						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
1986	68.1	5.3	6.6	68.7	304.1	2.4	455.2	15	1	1	15	67	1	100
1990	66.0	8.7	8.3	98.2	320.2	2.9	504.3	13	2	2	19	63	1	100
1995	81.2	9.5	10.1	112.4	335.7	3.9	552.8	15	2	2	20	60	1	100
2000	106.1	10.3	9.9	106.7	366.3	4.5	603.8	18	2	1	18	60	1	100

Source: Energy, Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

Capacity and Reserve Margins

CAPACITY ADDITIONS

In 1985, total generating capacity increased by 2897 MW to 97 948 MW at year end, a 3.1 per cent increase over 1984. Nuclear capacity additions totalled 1346 MW, hydro 1345 MW, and coal 206 MW, representing 47 per cent, 46 per cent, and 7 per cent of the total additions respectively. A summary of the major additions is presented in Table 16.

Total installed capacity by principal fuel type by province for 1985 is given in Table A2 and illustrated in Figure 6. Installed capacity by region and by energy source for Canada is shown in Figure 7. Figure 8 presents historical installed capacity for Canada during the period 1960-1985. Although the market share of hydro has decreased since 1960, it is still the most important source of electric power in Canada. In 1985, hydro accounted for 59 per cent of total installed generating capacity.

Table 16. Major additions to installed generating capacity during 1985

Additions	Project	Plant Type	No. of Units	Capacity (MW)
Newfoundland	Cat Arm	Hydro	2	127
Quebec	LG-4	Hydro	2	589
Ontario	Atikokan	Steam(coal)	1	206
	Bruce B	Nuclear	1	830
	Pickering B	Nuclear	1	516
Saskatchewan	Nipawin	Hydro	1	168
British Columbia	Revelstoke	Hydro	1	461

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Figure 6

Installed Capacity by Principal Fuel Type

1985 % of Provincial Total

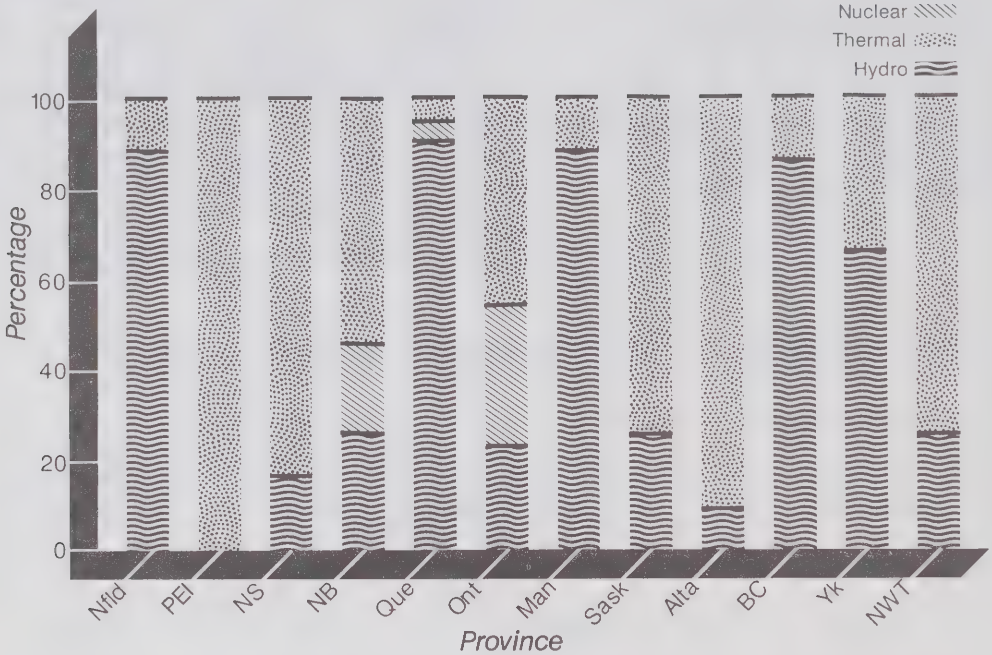
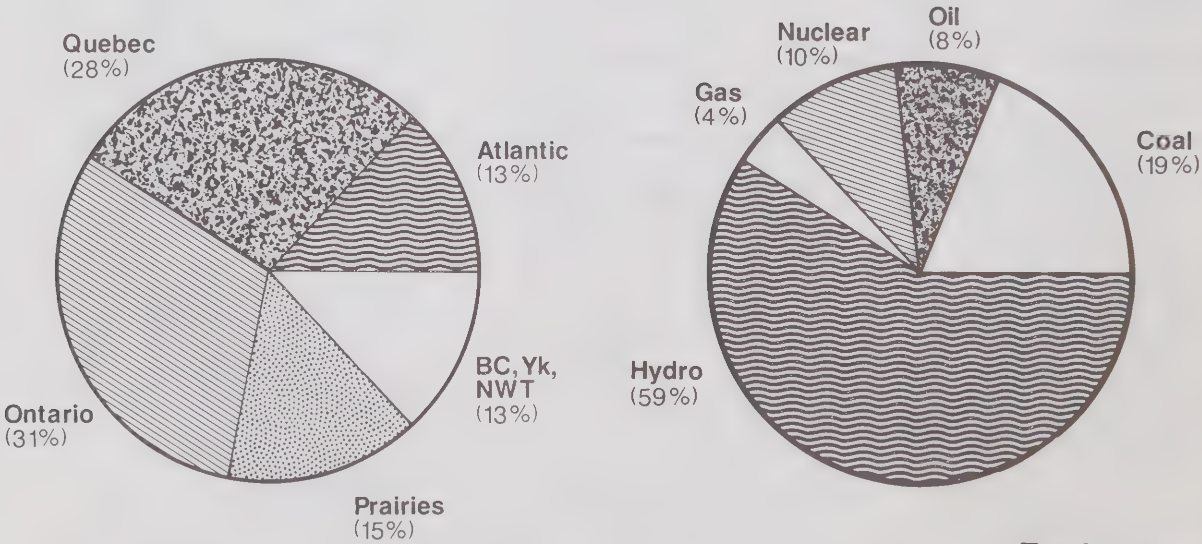


Figure 7

Capacity by Region and Capacity by Energy Source

1985

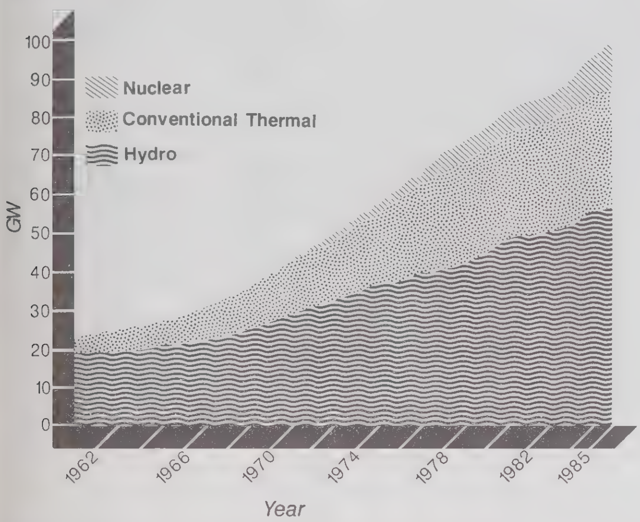


Total: 97 948 MW

Figure 8

Historical Installed Capacity by Fuel Type

1960–1985



FORECASTS OF GENERATING CAPACITY

To meet the forecast growth in electricity demand, total installed generating capacity in Canada is expected to increase at an average annual rate of 0.9 per cent, from almost 98 000 MW at the end of 1985 to 110 000 MW by the end of the century. The fact that this level of growth is significantly less than energy and peak demand growth reflects the current excess capacity situation in certain provinces. Forecasts of installed capacity, by energy source, are displayed in Table 17.

The largest share of total Canadian capacity over the next 15 years will continue to be hydro, with its 58 per cent share of total capacity remaining relatively stable through the period. Nuclear generating capacity, as a share of total capacity, is expected to increase from 10 per cent in 1986 to 13 per cent in 1990, and 14 per cent in 1995; it will then drop to 13 per cent by 2000. While coal-fired capacity is expected to increase moderately over the forecast period, its share is expected to be fairly stable at about 18 per cent of total capacity. Natural gas capacity will also remain stable, at 4 per cent for the period 1986-2000. Oil-fired capacity is expected to increase slightly over the period, although its share of total capacity is expected to decrease slightly from 8 per cent in 1985 to 6 per cent by the year 2000. Thus coal, nuclear, and hydro will continue to account for most of the electricity generated in Canada. These sources accounted for 88 per cent of total capacity in 1985, and this percentage is expected to increase slightly to 89 per cent by the year 2000.

RESERVE MARGINS

There have been two distinct periods in the growth of electricity demand in Canada since World War II. From 1947 to 1974 there was a period of rapid growth, with an average annual increase of 6.8 per cent. Following the oil crisis of 1973-1974, electricity growth slowed to an average rate of 3.9 per cent for the period 1975-1985. During the latter period, electricity consumption actually declined in 1975 and again in 1982.

This shift, from a long period of sustained rapid growth to one of slower growth, resulted in excess generating capacity. In the early 1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand and also to displace fossil-fuelled electricity production. As the growth in demand

slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to domestic requirements.

PRESENT RESERVE MARGIN

The reserve margin of an electrical system is defined as the excess of installed generating capacity over annual peak load expressed as a percentage of annual peak load. Column 3 of Table 18 presents the reserve margin in all ten provinces in 1985. The highest reserve was in Nova Scotia with 71 per cent, followed by New Brunswick with 55 per cent, British Columbia with 51 per cent, and Ontario with 36 per cent.

CAPACITY RESERVE REQUIREMENTS

Normal practice in an electrical system is that a certain proportion of installed capacity is designated to allow for scheduled maintenance, planned outage, and unexpected peak demand. This proportion is usually called the capacity reserve requirement. It varies from utility to utility depending on the installed capacity mix of the electrical system. Column 4 of Table 18 reports the capacity reserve requirement in each province for 1985. Ontario Hydro had the largest capacity reserve of 23 per cent, while Hydro-Québec had the lowest with 10 per cent.

SURPLUS GENERATING CAPACITY

Surplus generating capacity is defined as the reserve margin less the reserve capacity requirement. Although surplus generating capacity is defined in terms of peak domestic requirements, the surplus capacity may be utilized to supply export markets. Column 5 of Table 18 indicates surplus generating capacity by province for 1985. Despite significant growth in electricity demand in 1985, all provinces except Alberta had surplus capacity. In New Brunswick, Nova Scotia, and British Columbia, the surplus exceeded 30 per cent. The weighted surplus for Canada as a whole was 14 per cent.

Table 17. Forecasts of installed generating capacity by principal fuel type - Canada

	Installed Generating Capacity (GW)							Percentage of Installed Capacity						
	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total	Coal	Oil	Natural Gas	Nuclear	Hydro	Other	Total
1986	18.0	7.5	3.9	10.2	56.6	0.5	96.7	19	8	4	10	58	1	100
1990	18.1	7.5	3.6	13.7	58.1	0.6	101.6	18	7	4	13	57	1	100
1995	20.2	7.5	4.3	15.4	61.9	0.7	110.0	18	7	4	14	56	1	100
2000	21.7	7.9	4.2	15.4	69.8	0.8	119.8	18	6	4	13	58	1	100

Source: Energy, Mines and Resources, based on forecasts provided by the Utilities and the National Energy Board.

Table 18. Surplus of installed generating capacity in 1985

	Installed Capacity (MW) (1)	Peak Demand (MW) (2)	Reserve Margin (3)=(1)-(2)/(2)	Capacity Reserve Requirement (4)	Net Surplus (5)=(3)-(4)
Nfld.	2 056	1 735	19	12	7
P.E.I.	124	95	31	15	16
N.S.	2 250	1 319	71	20	51
N.B.	3 032	1 953	55	20	35
Que.	32 108	26 322	22	10	12
Ont.	29 395	21 644	36	23	13
Man.	3 948	3 043	30	15	15
Sask.	2 655	2 260	18	15	3
Alta.	6 623	5 456	22	22	0
B.C.	12 533	8 322	51	15	36
Canada*	95 022	72 367	31	17	14

* Figures include NCPC's capacity.

Source: Energy, Mines and Resources Canada.

Fuel Requirements

FUEL USE IN 1985

Electricity generated from conventional thermal and nuclear sources totalled about 146 TWh in 1985, or about 32 per cent of total generation. Fuels used for this generation in terms of heat contents amounted to the equivalent of 283 million barrels of oil. A breakdown of the fuels used by utilities is provided in Table 19. Ontario was the largest user, accounting for approximately 57 per cent of the total. Alberta was second, accounting for 20 per cent, and Saskatchewan ranked third with an 8 per cent share.

New Brunswick remained the largest user of oil due in part to a unit participation contract with Maine Electric Power Company (MEPCo). Under the contract, NB Power exported firm energy to MEPCo from its Coleson Cove oil-fired station. In 1985, more than 60 per cent of NB Power's oil-fired electricity production was exported to MEPCo. In 1986, it is expected that New Brunswick will reduce its electricity generation from oil by importing more hydroelectricity from Quebec.

Energy sources of electricity generation changed significantly in 1985 from the previous year. The decline in coal use is attributed mainly to a 16 per cent decline in export sales from Ontario. In 1985, more than 96 per cent of Ontario's electricity exports came from coal-fired stations. Uranium use increased due to the addition of Ontario's Bruce B and Pickering B stations. Oil and gas use also increased slightly, with most of the increase occurring in industrial establishments that generate their own electricity.

Provinces west of Quebec continued to use Canadian oil, primarily light oil, in gas turbines or diesel plants. In the Territories, Canadian diesel oil was used to supply electricity to small remote communities. All oil used by the Atlantic region and Quebec was imported.

Saskatchewan Power Corporation's 252-MW Nipawin hydroelectric project was nearly completed by the end of 1985. The main dam under construction can be seen to the left of the spillway.

Table 19. Fossil fuels used by utilities, 1985

Province	Coal (10^3 tonnes)	Oil (m^3)	Gas ($10^6 m^3$)	Uranium ($10^3 g$)
Newfoundland	-	459 132	-	-
Prince Edward Island	64	5 630	-	-
Nova Scotia	2 153	196 069	-	-
New Brunswick	486	599 357	-	120 000
Quebec	-	66 218	-	66 000
Ontario	11 000	8 205	184	907 000
Manitoba	252	3 815	-	-
Saskatchewan	8 280	18 944	145	-
Alberta	16 662	37 521	780	-
British Columbia	-	161 438	114	-
Northwest Territories/Yukon	-	61 041	-	-
Canada	38 897	1 617 370	1 223	1 093 000

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Table 20. Fuels required for electricity generation in Canada

	Coal (10^3 tonnes)	Oil (m^3)	Natural Gas ($10^6 m^3$)	Uranium ($10^3 g$)
1986	35 338	1 318 898	1 421	1 451 000
1990	36 229	2 135 231	1 981	1 806 000
1995	43 259	2 265 534	2 384	2 058 000
2000	52 024	2 442 632	2 258	1 954 000

Note: 1 cubic metre of oil = 6.3 bbls.
1 cubic metre of gas = 35.5 cubic feet.
1 tonne = 1000 kg.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

In 1985, about 73 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan. Alberta, Nova Scotia, and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal but also purchased additional amounts from Alberta.

In 1985, about 1.2 billion cubic metres of natural gas was used for electricity generation. Of this total, about 64 per cent was used by Alberta, with the remainder consumed by Ontario, Saskatchewan, and British Columbia. Electricity generated from natural gas is used mainly for peaking purposes.

FORECAST OF FUEL REQUIREMENTS

Forecast fuel requirements are reported in Table 20. These requirements are based on the forecasts of energy generation indicated in Table 15.

Coal consumption for electricity generation is expected to slowly increase from 35.3 million tonnes in 1986 to 43.3 million tonnes in 1995. This increase is slight primarily because of a substantial reduction in coal-fired generation in Ontario, which will reduce coal consumption from 11 to 6.5 million tonnes over the same period. The major increase in coal use will be in Alberta and Nova Scotia.

After 1995, Ontario is expected to use more coal for electricity generation, almost doubling its use from 6.5 million tonnes in 1995 to about 12.3 million tonnes by the year 2000. Canada's total consumption of coal is projected to reach 52 million tonnes by the end of the century.

Oil consumption is expected to increase moderately to 2.1 million cubic metres (or 13 million barrels) in 1990, and to 2.4 million cubic metres (or 15 million barrels) by the year 2000. Oil will be used primarily for peaking purposes and in remote locations.

Over the forecast period 1986 to 2000, the use of natural gas for electricity generation is projected to increase from 1.4 to 2.3 billion cubic metres. This 64 per cent increase is larger than those forecasted for coal, oil or uranium. Major electric utilities, mainly in Alberta, are the largest users of natural gas for electricity generation; their share is expected to be 56 per cent for the period 1986-2000. Industrial establishments, also mainly in Alberta, will account for the other 44 per cent.

With nuclear energy becoming an increasingly important component of Canadian electricity supply, the use of uranium for electricity generation is expected to increase substantially from 1451 tonnes in 1985 to about 1954 tonnes toward the end of the century, an average annual growth rate of 2 per cent.

Electricity Trade

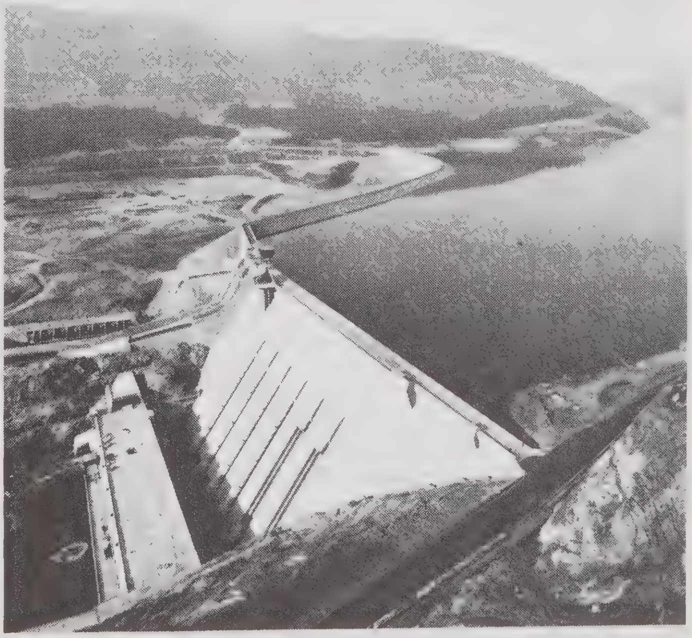
INTERNATIONAL TRADE

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line (12 000 volts) was built across the border at Niagara Falls. The purpose of this early interconnection was to enable Canada to market its abundant hydroelectric power in the United States. For most of the century, electricity trade between Canada and the United States has been balanced. Since the early 1970s, however, Canada's net exports to the United States have grown steadily, in both quantity and revenue. Electricity trade statistics for the period 1981-85 are summarized in Table 21.

In 1985, electricity exports to the United States (excluding non-cash service exchange) reached 41 520 GWh, accounting for 9.3 per cent of Canada's total generation, up from 8.8 per cent in 1984. Electricity imports from the United States in 1985 were 221 GWh. Total electricity export revenue increased to $1.4 billion in 1985, accounting for about 8.2 per cent of Canada's total energy export revenue and about 1.2 per cent of total merchandise exports. Import costs to Canada for the same year were about $9 million.

Approximately 70 per cent of the electricity exports reported in 1985 were interruptible, i.e. available only when surplus to the needs of the selling utility. Hydro-generated electricity continued to be the main source of Canada's electricity exports, accounting for more than 63 per cent of the total exported.

Provincial sources of exports and average revenues received in 1984 and 1985 are reported in Table 22. Four provinces - New Brunswick, Manitoba, Saskatchewan and British Columbia - showed increases in 1985, while Ontario's and Quebec's sales declined moderately.



BC Hydro's Revelstoke generating station was officially opened in August 1985. Construction of the four-unit 1800-MW station, located on the Columbia River, began in 1977.

Table 21. International electricity trade, 1981-1985

	1981	1982	1983	1984	1985
			(GWh)		
Exports[a]	34 730	32 986	36 907	37 572	41 520
Imports[a]	466	268	211	291	221
Net exports	34 264	32 718	36 696	37 281	41 299
Type of exports:[b]					
Firm	5 008	5 829	10 218	10 852	12 305
Interruptible	29 722	27 157	26 689	26 720	29 215
Total	34 730	32 986	36 907	37 572	41 520
Generation source for exports:[c]					
Hydro	19 948	18 574	19 237	20 555	25 537
Imported coal	10 901	10 315	11 704	10 582	8 245
Imported oil	1 940	1 959	1 201	1 552	1 157
Domestic coal/oil	665	502	519	711	956
Nuclear	42	96	1 856	1 911	2 247
Other[d]	1 234	1 540	2 390	1 352	2 175
Total	34 730	32 986	36 907	36 663	40 317
Revenue/Cost			(million $)		
Exports	1143.87	1105.90	1249.00	1376.00	1 424.78
Imports	5.62	5.41	5.80	9.61	8.95
Net revenue	1138.25	1100.49	1243.20	1366.39	1 415.83

(a) Excludes non-cash exchanges.
(b) Firm exports refer to energy that must be made available when the purchaser wants it. Interruptible exports refer to energy that is made available by the supplier only when surplus energy exists.
(c) Estimated from data of major utilities.
(d) Includes purchases for export where the generation source is not identifiable.

Source: National Energy Board.

Table 22. Electricity exports and revenues by province, 1984-1985*

	1984		1985		% Change
	Exports GWh	Revenue $/MWh	Exports GWh	Revenue $/MWh	in Export Quantities
New Brunswick	5 693	58.0	6 130	54.3	8
Quebec	11 240	34.5	9 585	34.6	-15
Ontario	11 056	40.2	9 329	40.7	-16
Manitoba	5 096	18.6	5 642	17.0	11
Saskatchewan	59	26.9	128	25.7	117
British Columbia	4 428	26.9	10 706	26.3	142
Canada	37 572	36.6	41 520	34.3	11

* Exchanges are excluded.

Source: Statistics Canada Publication 57-202 1983.
National Energy Board 1984-1985.

British Columbia's exports increased dramatically during the spring and summer periods because of drought conditions in the U.S. Pacific Northwest. However, the drought ended in early 1986, and British Columbia's exports are expected to decline this year.

The decrease in Ontario's exports resulted from strong growth in domestic consumption. Ontario's demand for electricity increased 3.4 per cent in 1985, exceeding the forecasted rate of 2.6 per cent. As a consequence, there was less electricity available to sell outside the province. A lack of transmission lines in southwestern Ontario and price competition among utilities for the midwestern U.S. market were also factors. The decline of export sales in Quebec was mainly due to increased nuclear and hydro generation in New England and the State of New York.

The average revenue received from electricity exports in 1985 varied significantly from province to province. New Brunswick received the highest average revenue, $54.3 per MWh, while Manitoba received the lowest, $17 per MWh. The factors that affect the value of electricity exports include whether the electricity is exported on a firm or interruptible basis, the generating costs of the exporting utility, the generating costs avoided by the importing utility, and the cost of transmission.

Interruptible electricity supply is less valuable to the importing utility because it must maintain standby generating capacity. The generating cost incurred by the exporter and avoided by the importer varies according to the type of electricity generation. For base load generation in both Canada and the United States, oil-fired generating plants tend to be the most costly and hydro plants the least costly.

Table 23 presents the proportion of firm and interruptible electricity exports for the six exporting provinces. While firm exports accounted for just under 30 per cent of total Canadian electricity exports in 1985, the proportion of firm to total exports ranged from 8 per cent in Manitoba to almost 44 per cent in New Brunswick. The high proportion of firm power exports in New Brunswick partly accounts for it receiving the highest average revenue.

Table 24 reports the energy sources of electricity exported during 1985. Exports from Quebec and British Columbia were generated entirely from hydroelectric stations. Manitoba's exports also overwhelmingly came from hydro. Exports from Saskatchewan were generated entirely from indigenous coal, while Ontario's exports come primarily from thermal stations using imported coal. In New Brunswick, the generation sources were nuclear, oil, and coal. New Brunswick was the only province using base load oil-fired generation for exports because of a unit participation agreement it has with Maine Electric Power Company. The contract stipulates that New Brunswick is to export firm power to Maine from the Coleson Cove oil-fired station.

Table 23. Gross firm and interruptible exports, 1985*

	Firm	Interruptible	Per cent Interruptible	Per cent Firm
	(MWh)			
New Brunswick	2 677 667	3 452 750	56.3	43.7
Quebec	3 423 099	6 161 784	64.3	35.7
Ontario	3 897 620	5 431 152	58.2	41.8
Manitoba	454 475	5 187 334	91.9	8.1
Saskatchewan	11 650	116 095	90.9	9.1
British Columbia	1 840 466	8 865 793	82.8	17.2
Canada	12 304 977	29 214 908	70.4	29.6

* Exchanges are excluded.

Source: National Energy Board.

Table 24. Energy sources of electricity exports, 1985 (per cent)

	Oil	Coal	Nuclear	Hydro	Other	Total
New Brunswick	20.4	9.4	34.9	-	35.3	100
Quebec	-	-	-	100.0	-	100
Ontario	0.1	96.4	2.5	0.2	0.8	100
Manitoba	-	5.2	-	93.1	1.7	100
Saskatchewan	-	100.0	-	-	-	100
British Columbia	-	-	-	100.0	-	100

Source: Energy, Mines and Resources Canada.

The export markets in the U.S. and the types of electricity generation displaced by Canadian exports are presented in Table 25. In all markets, Canadian exports displaced fossil-fuel generation.

The provincial shares of total Canadian electricity exports are shown in Table 26. British Columbia was the leading exporter in 1985, followed by Quebec and Ontario. For the period 1983-85, Ontario and Quebec were the leading exporters.

Table 26. Provincial share of Canadian exports (per cent)

	1983	1984	1985
New Brunswick	15	15	15
Quebec	28	30	23
Ontario	33	29	22
Manitoba	16	14	14
British Columbia	8	12	26
Canada	100	100	100

Source: Energy, Mines and Resources Canada.

Table 25. Fuel displacement of exports

Exporting Province	Importing States	Fuel Displaced
New Brunswick	New England	Oil
Quebec	New England	Oil
	New York	Oil, coal
Ontario	New York	Oil, coal
	Michigan	Coal
	Wisconsin	Coal
Manitoba	North Dakota	Coal
	Minnesota	Coal
Saskatchewan	North Dakota	Coal
British Columbia	California	Oil, coal, gas

Source: National Energy Board.

A summary of electricity exports projected by electric utilities is presented in Table 27. Total Canadian electricity exports are expected to continue to increase until the end of the decade. The increase, if it is realized, will be largely attributed to a growth in exports from Quebec. Beyond 1990, total Canadian exports are forecast to gradually decline from 50.8 TWh in 1990, to 40.3 TWh in 2000. The exception to this post-1990 trend is Manitoba, where exports are expected to continue to increase beyond the year 2000.

Atikokan generating station in northwestern Ontario came into service in November 1985. The 200-MW station burns low-sulphur lignite coal from western Canada.

Table 27. Utilities' forecasts of electricity exports (TWh)*

	1985	1986	1987	1990	1995	2000
N.B.	6.1	6.6	5.8	5.5	2.4	1.8
Que.	9.6	18.1	21.4	27.5	17.7	15.4
Ont.	9.3	9.7	10.6	13.0	14.8	9.6
Man.	5.6	7.8	6.3	4.4	9.0	13.1
Sask.	0.1	0.1	0.1	0.1	0.1	0.1
B.C.	10.7	1.0	0.5	0.3	0.3	0.3
Canada	41.4	43.3	44.7	50.8	44.3	40.3

* Exchanges are excluded.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

INTERPROVINCIAL TRADE

The most significant change in interprovincial transfers during 1985 was a decline in net exports from Newfoundland to Quebec, where net exports decreased by 12 per cent, from 36 043 GWh in 1984 to 31 837 GWh in 1985. This change was partly due to decreased electricity exports from Quebec to the United States.

Although Quebec's purchases from Newfoundland declined, its sales to Ontario and New Brunswick increased substantially. Net transfers from Quebec to Ontario and New Brunswick grew by 18 and 35 per cent, respectively. Net interprovincial transfers are outlined in Table 28. More information on exports and imports by province is provided in Figures 9 and 10 and Table A5.

Table 28. Net interprovincial transfers (12-month period)

	GWh		Per Cent
	1984	1985	Growth
BC to Alberta	36	32	-10
Saskatchewan to Alberta	4	3	-34
Manitoba to Saskatchewan	327	323	-1
Manitoba to Ontario	937	963	3
Quebec to Ontario	7 300	8 625	18
Newfoundland to Quebec	36 043	31 837	-12
Quebec to New Brunswick	4 306	5 825	35
New Brunswick to PEI	539	575	7
New Brunswick to Nova Scotia	20	151	671

Source: Statistics Canada.

Figure 9

Net Transfers and Exports of Electrical Energy, 1985(GWh)

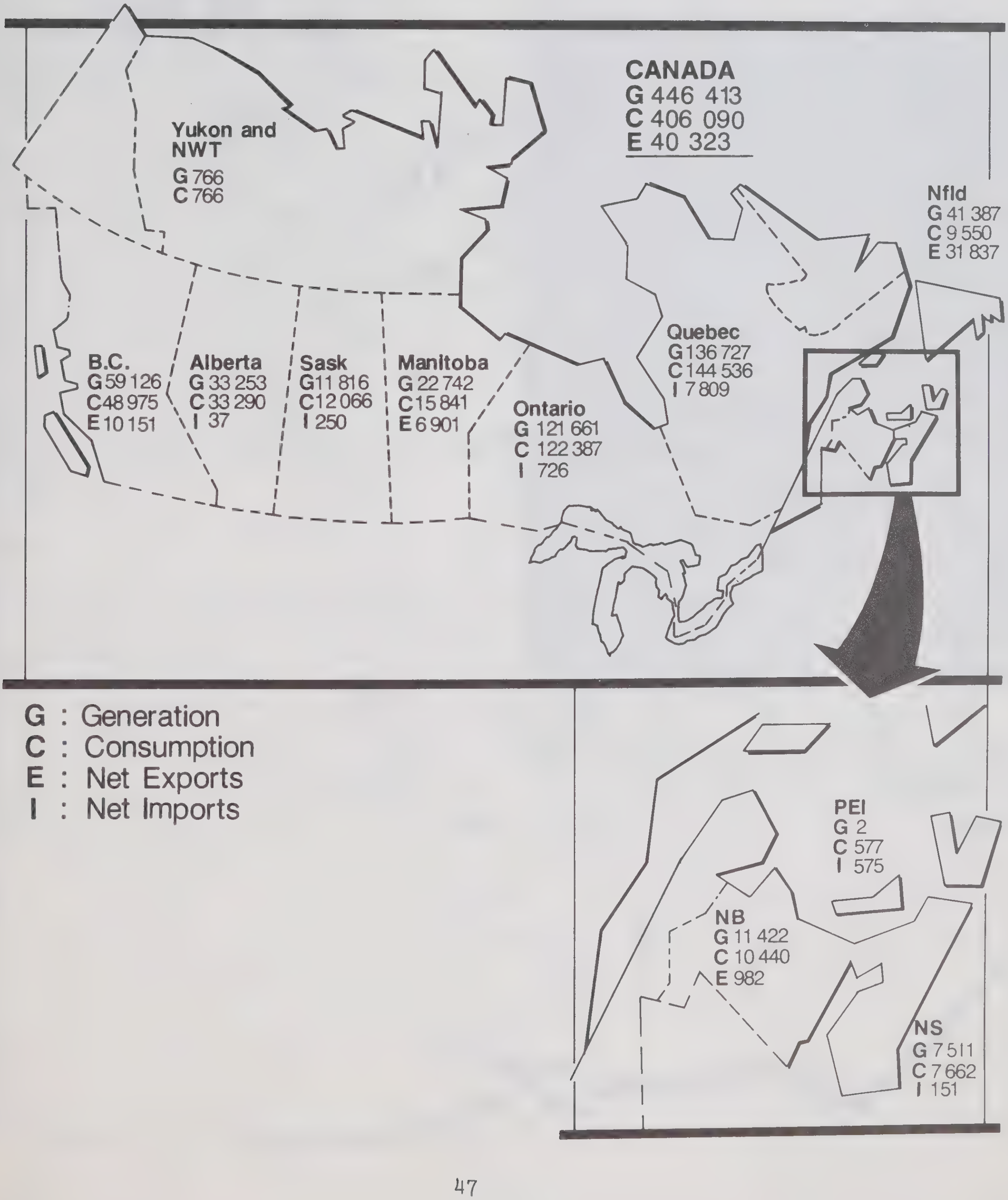
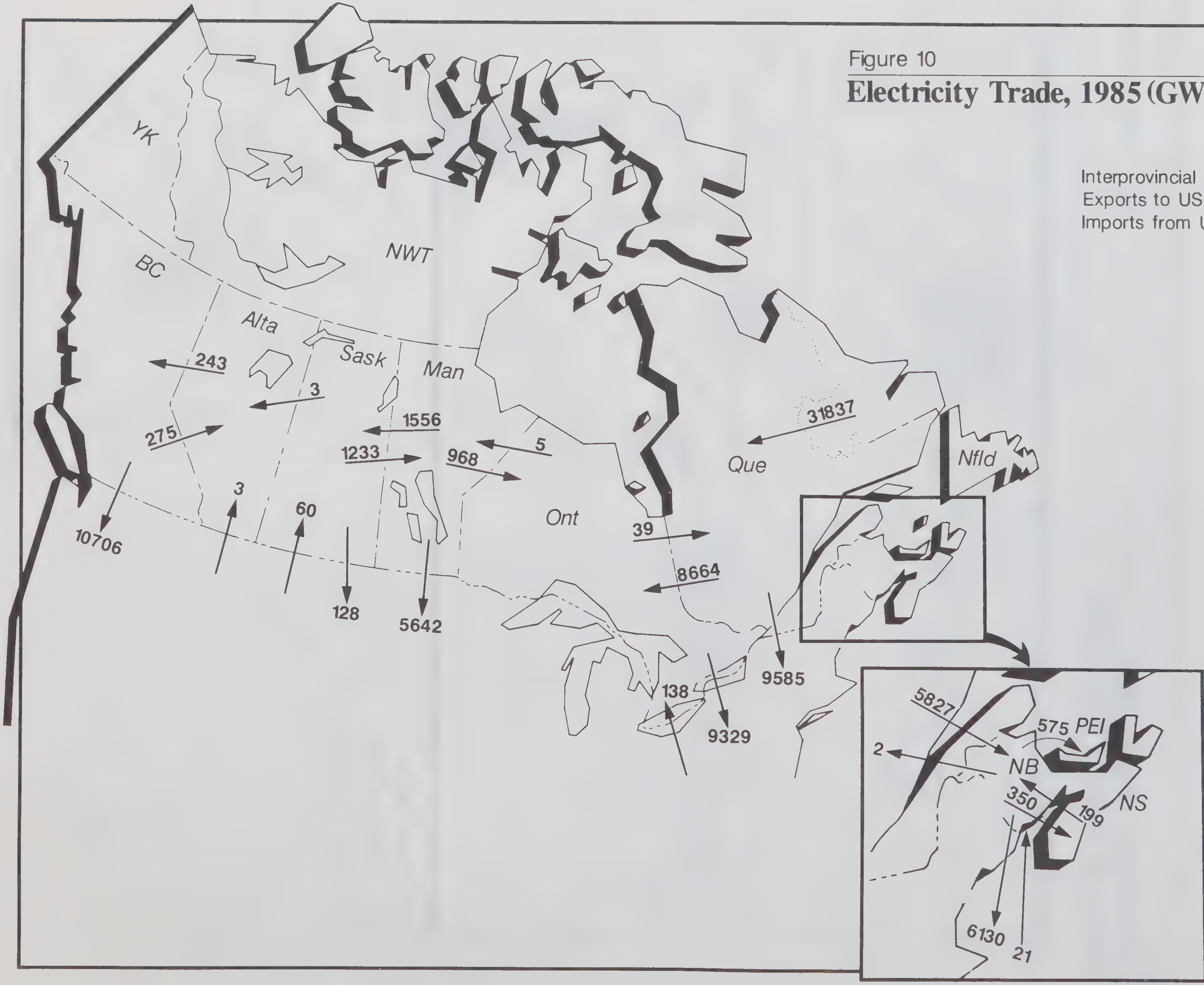


Figure 10

Electricity Trade, 1985 (GWh)

Interprovincial total 51,776
Exports to US total 41,520
Imports from US total 222



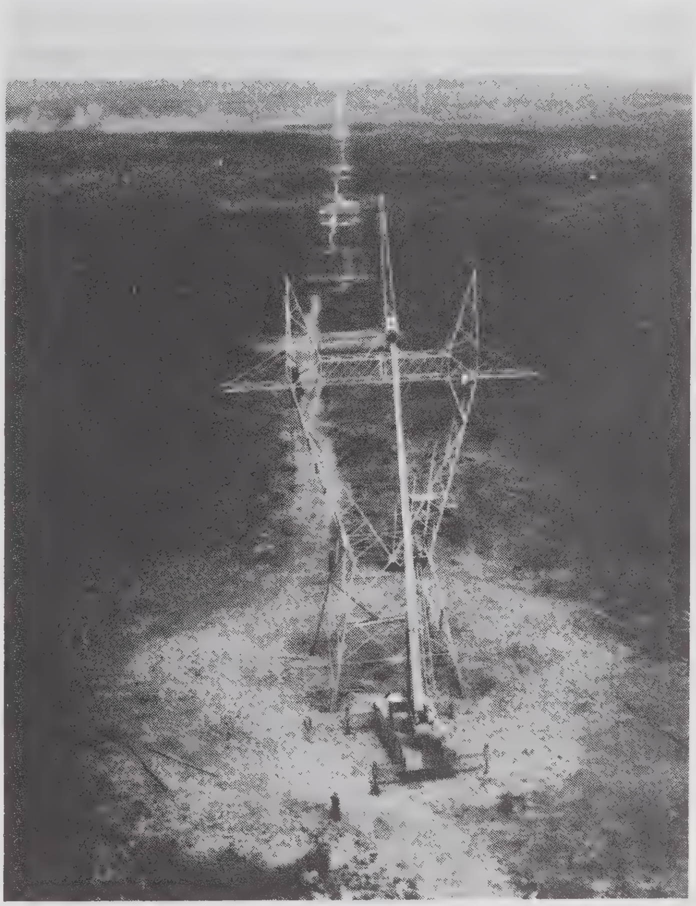
Transmission

CANADA

Total electrical transmission in Canada, for lines rated at 100 kV and above, increased from 112 667 km in 1984 to 113 510 km in 1985, an increase of 843 km or 0.7 per cent. The largest proportion of Canada's transmission (41 per cent) is in the range of 100 kV to 149 kV. Another 34 per cent is in the 150-299 kV range, while 16 per cent is between 300 kV and 599 kV. Newfoundland and Quebec are the only two provinces with transmission lines over 600 kV; their length is 10 529 km, about 9 per cent of the Canadian total. Quebec has the greatest amount of electrical transmission, with 29 968 km or 26.4 per cent of Canada's total. It is followed by Ontario with 24.5 per cent and British Columbia with 12.3 per cent. A summary of transmission length by province and voltage is reported in Table 29.

PROVINCIAL

There were very few additions to provincial transmission lines in 1985. Alberta Power increased its 144 kV lines by 156 km; Hydro-Québec added 98 km to its system; Saskatchewan Power completed 80 km of 230-kV lines in order to integrate the Nipawin hydroelectric power plant into the grid; and Newfoundland increased its system by 19 km with the addition of one 138-kV line.



New Brunswick Power's second major interconnection with Hydro-Québec under construction. The 345-kV line has doubled New Brunswick's interchange capacity with Quebec from 500 MW to 1000 MW.

Table 29. Transmission length at year-end (km)

	100 - 149 kV	150 - 199 kV	200 - 299 kV	300 - 399 kV	400 - 599 kV	600 kV and up	Total
Newfoundland	1 682	214	1 881	0	0	600	4 377
Prince Edward Island	100	0	0	0	0	0	100
Nova Scotia	1 555	0	1 150	173	0	0	2 878
New Brunswick	1 994	0	528	827	0	0	3 349
Quebec	7 540	2 147	3 615	6 737	0	9 929	29 968
Ontario	12 149	0	13 453	6	2 222	0	27 830
Manitoba	4 139	0	4 030	0	2 042	0	10 211
Saskatchewan	3 599	0	2 598	0	0	0	6 197
Alberta	8 248	133	4 955	0	355	0	13 691
British Columbia	4 261	220	3 915	427	5 086	0	13 909
Yukon	497	0	0	0	0	0	497
Northwest Territories	503	0	0	0	0	0	503
Canada	46 267	2 714	36 125	8 170	9 705	10 529	113 510
% of Total	41	2	32	7	9	9	100

Sources: Statistics Canada Publication 57-202.
Energy, Mines and Resources Canada - Utility Questionnaire.

INTERPROVINCIAL

There were two additions to provincial interconnections during 1985: a 345-kV transmission line from New Brunswick's Edmundston substation to the substation at Madawaska, Quebec, and a 500-kV line from Alberta to Cranbrook, British Columbia. Table 30 presents the major provincial interconnections. In total, there are 33 interties with a transfer capability of 10 000 MW. There are no provincial interconnections under construction or proposed at this time.

Table 30. Provincial interconnections

Connection	Voltage (kV)	Capability Installed (MW)	Capability Firm (MW)
British Columbia - Alberta	1 x 500	800	600
	1 x 138	110	80
Saskatchewan - Manitoba	3 x 230	400	400
Manitoba - Ontario	2 x 230 1 x 115	260	260
Quebec - Ontario	4 x 230 9 x 120	1300	1300
Quebec - Newfoundland	3 x 735	5225	4300
Quebec - New Brunswick	±80(DC)	350	350
	1 x 230	150	150
	2 x 345	500	500
New Brunswick - Nova Scotia	2 x 138 1 x 345	600	600
New Brunswick - Prince Edward Island	1 x 138	200	100

Source: Energy, Mines and Resources Canada.

Table 31. Major interconnections between Canada and the United States*

Province	State	Voltage (kV)	Power Transfer Capability (MW)
New Brunswick	Maine	345	600
		5 x 69	330
Quebec	New York	765	1400
	New York	2 x 120	200
	Vermont	2 x 120	200
Ontario**	New York	230	470
		230	400
		2 x 230	600
		2 x 345	2300
		4 x 69	265
	Michigan	230	535
		230	515
		345	710
		345	760
	Minnesota	120	35
Manitoba	North Dakota	230	150
	Minnesota	230	175
	Minnesota	500	1000
Saskatchewan	North Dakota	230	150
British Columbia	Washington	230	350
		230	300
		2 x 500	1400

* 35 MW capacity or over.
** The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

INTERNATIONAL

One new international transmission line was completed during 1985. This was a 120-kV line from Quebec to Vermont, with a power transfer capability of 200 MW. There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 34 bulk power interties rated at 69 kV or higher with a total power transfer capacity of almost 13 000 MW. These are presented in Table 31.

To accommodate Quebec's inceasing exports to the New England states, one ±450-kV HVDC transmission line to New Hampshire is now under construction. The intertie capacity between Quebec and New England will increase from 690 MW to 2000 MW when the line is completed in 1986. A 345-kV transmission line from Pointe Lepreau to Maine is planned by New Brunswick, and it is expected to be completed in 1988. Planned interconnections between Canada and the United States are given in Table 32.

Table 32. Planned interconnections to the United States

Province	State	Completion Date	Voltage (kV)	Estimated Power Transfer Capability (MW)
Quebec	New Hampshire	1986	±450 DC	690*
NB	Maine	1988	345	575

* May be upgraded to 2000 MW by 1990.

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

Electric Utility Investment and Financing

CAPITAL INVESTMENT

Electric utility investment in new facilities was $5.9 billion in 1985, slightly less than the $6.3 billion spent in 1984. Approximately 51 per cent of the 1985 total was for generation, 18 per cent for distribution, 15 per cent for transmission, and the remainder for other items. Table 33 illustrates the capital-intensive nature of electricity and its importance in the Canadian economy. It is interesting to note that electric utility investment in Canada, as a share of total capital spending and GNP, has declined since 1983. Overcapacity in the electric power industry has been the main reason for the reduction in capital investment over the past three years.

Table 34 shows the original cost of utility fixed assets in service. The ratio of generation investment to total investment has increased from 53 per cent in 1981 to about 57 per cent in 1985. This investment pattern varies from one region to another, depending on the generation mix employed. Capital investment, per unit of capacity added, is significantly higher for hydro and nuclear capacity than for conventional thermal capacity. Hydro and nuclear generation are characterized by high capital costs and low operating costs, relative to conventional thermal generation. In addition, hydro facilities often require higher capital expenditures for transmission facilities, because of the remote location of many generating plants.

Table 35 presents forecast capital expenditures for electrical system expansion in each province for the period 1986-1995. Capital expenditures were expected to decline until 1986, reflecting present excess generating capacity. After 1986, capital expenditures are forecast to increase again, reaching a new peak in 1995. Over the next ten years, electric utilities in Canada will invest about $71 billion. Quebec will be the largest spender, with a total of $24 billion or 34 per cent of the Canadian total. Ontario is second with $22 billion or 30 per cent of the total. In third place is Alberta, which is expected to invest $5.5 billion or 8 per cent of the total. Because of a large surplus of generating capacity, British Columbia is not expected to invest in new generating stations until 1995. For the period 1986-1995, British Columbia anticipates spending $2.5 billion, with about 40 per cent to be spent in 1994 and 1995.

Capital expenditures projected by the electric utilities for 1986 continue to emphasize a shift in investment patterns. An increasing emphasis will be put on upgrading transmission and distribution systems over the next few years, with relatively less emphasis on generation facilties due to the existing surplus situation.

The historical data in Table 36 indicates that electric utility investment has increased at an average annual rate of 9.6 per cent since 1965. The average annual rate of inflation (measured by the Gross National Expenditure deflator) over this period was 7.1 per cent, suggesting that real growth was approximately 2.5 per cent.

FINANCING

From 1960 to 1976 debt for utility expansion increased as a percentage of total capital employed. The debt ratio was relatively stable until 1978 and then declined for the period 1979-82 as most utilities tried to reduce their exposure to high interest rates. However, the debt proportion increased again in 1983 as electric utilities increased their investment and borrowings. In 1984, overall capital expenditures declined relative to the previous year, and the debt ratio also declined, from 80 per cent in 1983 to 78 per cent in 1984. Table 37 shows electric utility debt ratios during the period 1976-84. In 1976, debt accounted for 83 per cent of capitalization in provinces with predominantly provincially owned utilities. In those provinces with predominantly investor owned utilities, it accounted for 50 per cent. In 1984, debt had decreased to 81 per cent for provincially owned utilities and 49 per cent for investor owned utilities.

In 1984, utilities used internally generated funds for about 35 per cent of capital expenditures. This was substantially higher than the 28 per cent of 1983. Internally generated funds are expected to meet about 30-35 per cent of capital requirements over the next five years.

Table 33. Electric utility capital investment

	1966-70	1971-75	1980	1981	1982	1983	1984	1985
Investment in electric power ($ billions)	6.8	12.9	6.1	7.3	8.4	7.8	6.3	5.9
Energy share*(%)	55	56	42	40	39	42	37	35
Economy share*(%)	8	9	9	9	11	10	8	7
GNP share*(%)	1.9	2.0	2.1	2.2	2.5	2.0	1.5	1.3

* The figures indicate electrical utility capital investment as a percentage of total energy investment, investment in the economy as a whole, and GNP.

Source: Statistics Canada Publications 61-205 and 11-003E.

Table 34. Original cost of utility fixed assets in service

	1981		1982		1983		1984		1985	
	(millions)	(%)	(millions)	(%)	(millions)	(%)	(millions)	(%)	(millions)	(%)
Generation	24 943	53	28 352	54	34 203	56	40 734	58	43 574	57
Transmission	9 632	20	10 828	20	12 035	20	13 214	19	14 021	19
Distribution	9 554	20	10 650	20	11 836	19	12 942	18	13 915	18
Other	3 145	7	3 031	6	3 409	5	3 709	5	4 622	6
Total	47 274	100	52 861	100	61 483	100	70 599	100	76 132	100

Source: Statistics Canada Publication 57-202.
Data for 1985 preliminary.

Table 35. Forecast of capital expenditures by electric utilities

	(Millions of Current Dollars)									
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Nfld.	49	96	411	488	419	437	460	571	400	450
P.E.I.	13	15	7	7	7	8	9	10	10	10
N.S.	151	103	119	203	230	179	185	351	507	500
N.B.	152	143	157	130	216	198	202	193	334	264
Que.	1 580	2 230	2 580	2 480	2 250	2 247	2 402	2 263	2 641	3 383
Ont.	2 564	2 312	2 209	1 924	2 054	2 090	2 020	1 791	2 067	2 515
Man.	284	443	447	504	552	414	532	390	900	1 149
Sask.	162	213	262	276	342	361	234	390	548	667
Alta.	607	509	484	519	577	473	509	556	638	616
B.C.	159	141	136	155	198	196	222	232	362	662
Yuk./NWT	12	19	7	10	2	4	4	7	8	8
Canada	5 733	6 224	6 819	6 696	6 847	6 607	6 779	6 754	8 415	10 224

Source: Energy, Mines and Resources Canada - Utility Questionnaire.
Fiscal and calendar years combined.

Table 36. Historical electric utility investment

Year	Construction: Generation	Construction: Transmission and Distribution*	Construction: Other	Sub-Total	Machinery and Equipment	Total
	(millions of current dollars)					
1965	438	277	12	727	212	939
1966	493	281	13	787	356	1143
1967	577	262	36	875	390	1265
1968	533	301	54	889	443	1332
1969	511	281	63	856	546	1403
1970	581	449	28	1057	554	1610
1971	572	472	36	1079	668	1747
1972	636	449	50	1135	619	1754
1973	808	539	69	1417	827	2244
1974	1049	598	53	1700	1054	2753
1975	1691	874	96	2661	1296	3957
1976	1803	821	30	2654	1574	4229
1977	2205	911	43	3158	1726	4884
1978	2339	1199	233	3771	2175	5946
1979	2516	1424	181	4121	2243	6364
1980	2470	1433	95	3998	2111	6109
1981	2768	1554	92	4414	2905	7319
1982	3153	1818	320	5291	3086	8377
1983	2663	1755	202	4620	3150	7770
1984(a)	-	-	-	3268	3072	6340
1985(a)	-	-	-	3079	2824	5903

* Transmission and distribution includes street lighting. Generation includes transformer stations, dams and reservoirs.
(a) Preliminary actual data, no breakdown available.
Note: The totals may not correspond with the sum of the elements due to rounding.

Source: Statistics Canada Publications 57-202, 61-205, and Canada Year Book 1968-79.

Table 37. Electric utility debt ratio (per cent)

	1976	1977	1978	1979	1980	1981	1982	1983	1984
Newfoundland	79	76	76	76	74	71	73	78	72
Prince Edward Island	53	53	52	53	54	55	55	68	61
Nova Scotia	103	102	99	98	95	97	97	96	96
New Brunswick	92	92	93	93	91	91	90	89	88
Quebec	76	76	76	75	75	75	75	75	76
Ontario	77	77	78	78	78	78	80	79	80
Manitoba	97	97	96	94	94	95	96	96	96
Saskatchewan	73	77	78	78	80	85	89	92	94
Alberta	49	47	44	45	42	42	49	70	49
British Columbia	94	95	94	86	85	85	85	86	87
Yukon/ N.W.T.	102	99	98	98	98	99	98	96	93
Canada	80	80	80	78	77	77	78	80	78

Debt ratio = debt/(debt + equity).
Debt: Long-term + short-term loans and notes payable.
Equity: Total of capital, reserves, and surplus.

Source: Statistics Canada Publication 57-202.

Costing and Pricing

ELECTRICITY SUPPLY COSTS

The unit cost of supplying additional electricity increased rapidly during the period 1974-1982. However, cost increases have moderated significantly since then; adjusted for inflation, the real increases in the cost of electricity have been small. This is expected to be the case for the next several years.

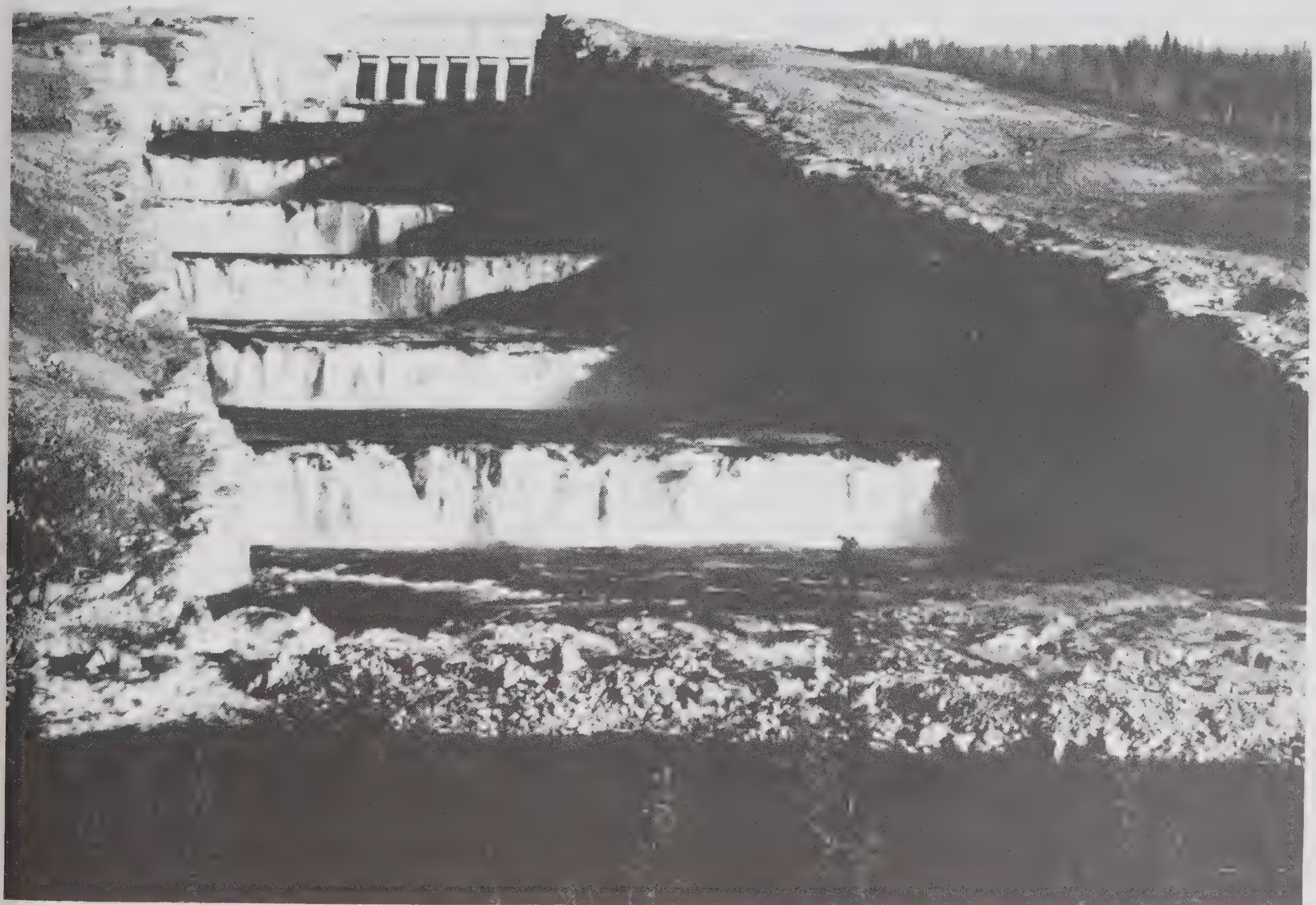
In the 1974-1982 period, there were two basic reasons for the rapid increases in the cost of electrictity: the high rate of inflation, with an average increase of 10 per cent annually; and the increased cost of fossil fuels, with an average annual increase of 16 per cent. High levels of inflation affect the electric utility industry in two ways, by increasing the cost of constructing additional facilities and by increasing the cost of borrowed funds.

The average interest rate on new long-term utility debt for the period 1960-1985 is shown in Figure 11. Interest rates started to rise in 1974, which coincided with the first oil crisis. The increase in interest rates reached a peak of 16.3 per cent in 1981 and 15.9 per cent in 1982, then dropped substantially in 1983 and thereafter. In 1985, interest rates averaged 11.7 per cent; however, an inflation rate of 4 per cent, as measured by the Consumer Price Index (CPI), suggests that the real interest rate was about 7.7 per cent.

The indices of electric utility construction costs, presented in Figure 12, show that increases in both hydro and steam construction costs between 1968 and 1985 have exceeded increases in the CPI. The average increase in construction costs during the period 1973-85 was 8.0 per cent for hydro projects and 8.6 per cent for thermal stations, compared to 7.4 per cent for the CPI. In general, electricity construction costs tend to parallel the CPI.

Increases in fossil-fuel costs since 1969 are summarized in Figure 13. Fuel costs for electricity generation were generally stable until the oil crisis of 1973, after which they began to rise. For Canada as a whole, the fuel cost per kWh generated from fossil fuels increased more than four-fold between 1973 and 1984, from 3.1 mills to 13.3 mills. The increase in the cost of fuel from oil generation was much more dramatic, growing from 7.1 mills to 56.1 mills per kWh during the same period, an average annual increase of 21 per cent. The cost of oil-fired generation peaked at 57.3 mills per kWh in 1983, and then dropped to 56.1 mills in 1984.

The unit cost of fuel generated from coal varies between regions of the country and depends on the type of coal used, its source, and the percentage of total energy supply derived from fossil fuel plants. The unit fuel cost of electricity generated from western coal increased from 1.4 mills per kWh in 1973 to 5.9 mills per kWh in 1984; in comparison, the cost of eastern coal-fired generation was 4.7 mills and 24.9 mills during the corresponding period.



La Grande 2's spillway has a discharge capacity of 15 300 m^3/sec, twice the average flow of the St. Lawrence River. Each of the eight flood control gates is 12 metres wide by 20 metres high.

PRICING

The average revenue from electricity sales for each province is provided in Table 38. Because electricity rates are regulated to cover costs, the average revenue per unit of electricity began to increase significantly in 1975, with the escalation in the cost of electricity generation. The average annual growth in unit revenue for Canada as a whole was 12.1 per cent during the period 1975-1984. The national inflation rate, as measured by the CPI, was 8.6 per cent over the same period, implying a real increase of 3.5 per cent.

Electricity costs increased more rapidly in some regions than others because of differences in generation mix, fuels used, population size, and rates of system expansion to meet increased demands for electricity. These factors account for the differences in electricity rates across the country. Table 39 gives monthly electricity costs for selected Canadian cities. Table 40 details the average annual rate increases for customers in each province since 1976.

Figure 14 illustrates the movement of the electricity, oil, and natural gas components of the CPI, and the movement of the energy price index, as well as the CPI itself. It indicates that the electricity price component increased more slowly than, or equal to, the rate of increase of the CPI for the period 1971-1976. Since 1977, the electricity price index has been consistently greater than the CPI; however, it has increased significantly more slowly than the oil and gas price indices.

Table 38. Average revenue from electricity sales by province

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
	(current cents/kWh)									
Nfld.	1.4	1.4	1.7	2.0	2.2	2.3	2.8	3.6	3.7	3.8
P.E.I.	4.1	5.1	5.9	6.4	7.2	8.1	10.0	12.0	12.4	12.8
N.S.	2.5	2.8	3.9	4.4	4.6	4.5	4.9	5.9	6.9	7.2
N.B.	1.9	2.0	2.4	3.2	3.7	4.1	4.8	5.1	5.3	5.5
Que.	1.3	1.4	1.5	1.7	2.0	2.2	2.6	3.1	3.3	3.4
Ont.	1.6	1.8	2.3	2.4	2.6	2.9	3.2	3.6	3.9	4.4
Man.	1.4	1.7	1.9	2.3	2.7	2.8	2.8	2.9	3.0	3.4
Sask.	1.8	2.1	2.4	2.7	2.7	2.9	3.6	4.0	4.2	4.5
Alta.	2.0	2.4	2.7	3.1	3.2	3.4	4.1	4.9	5.2	5.4
B.C.	1.6	1.8	2.1	2.2	2.4	2.6	3.0	3.8	3.8	4.5
Yukon	2.7	3.5	4.1	4.4	4.9	5.3	6.7	8.3	8.3	8.6
N.W.T.	4.0	5.2	6.9	7.7	9.0	10.0	11.5	14.8	17.9	14.1
Canada	1.5	1.7	2.0	2.3	2.5	2.8	3.1	3.7	3.9	4.2

Source: Statistics Canada Publication 57-202.

Table 39. Monthly electricity costs for selected Canadian cities, January 1985

Sector	Residential	Commercial	Industrial
Billing Demand (KW)	-	100	1000
Consumption (KWh)	1000	25 000	400 000
	(dollars)		
St. John's	74.06	1 889.50	24 090.62
Charlottetown	117.60	3 419.56	44 359.86
Halifax	65.72	2 047.21	21 134.61
Moncton	60.88	1 948.12	19 480.00
Montreal	38.90	1 334.10	15 492.80
Ottawa	45.36	1 184.18	16 814.18
Toronto	50.91	1 564.00	18 970.00
Winnipeg	36.44	963.25	10 940.77
Regina	47.26	1 497.20	19 009.70
Calgary	50.48	1 469.71	16 949.39
Edmonton	48.30	1 458.40	18 644.52
Vancouver	51.41	1 284.37	15 462.10
Whitehorse	69.30	2 205.00	-
Yellowknife	95.00	3 255.50	48 605.00

Source: Statistics Canada Publication 57-203.

Table 40. Average annual rate increases, 1976-1985

	Rate Changes (%): Average of all Customer Classes									
Utility	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Newfoundland Hydro	14.0	8.4	25.0	-	19.0	15.8	-	18.2	-	-
Newfoundland Light & Power	13.4	9.8	21.2	12.4	11.8	14.6	-	12.0	-	-
Maritime Electric	(8.0)	17.0	13.0	-	13.1	21.4	-**	-**	-**	3.7
Nova Scotia Power	-	43.0	14.0	12.5	-(2)	-	-	36.6	-	-
New Brunswick Power	12.0	16.6	9.9	7.9	7.8	9.8	-	8.8	6.2	4.6
Hydro-Québec	10.3	9.9	18.7	13.7	13.3	10.6	16.3	7.3	4.0	4.0
Ontario Hydro	14.9	25.6	5.7	7.7	7.3	10.0	10.0	8.2	7.5	8.6
Manitoba Hydro	16.6	15.0	14.9	14.4	-(1)	-	-	9.5	7.9	5.0
Saskatchewan Power	13.0	17.0	3.3	8.3	7.9	16.1	-	12.6	9.2	-
Edmonton Power	10.1	6.0	8.1	-	26.0	12.0	13.2	8.0	5.0	6.7
TransAlta Utilities	25.8	14.7	15.6	7.5	-	13.0	4.0	15.0	-	1.7
Alberta Power	11.4	20.2	-	-	12.3	28.9	-11.6*	-	-	-4.3
B.C. Hydro	14.2	12.1	13.4	5.5	7.6	2.6	20.0*	6.0	6.5	3.8

(1) The provincial government froze rates from 1979 until 1983.
(2) The provincial government froze rates in 1980.
* Based on residential category. (Alberta Power's reduction in rates is a result of Alberta Electric Energy Marketing Agency rebate.)
** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.

Source: Energy, Mines and Resources Canada.

Figure 11

Average Interest Rate on Public Utility New Long-Term Debt

1960–1985

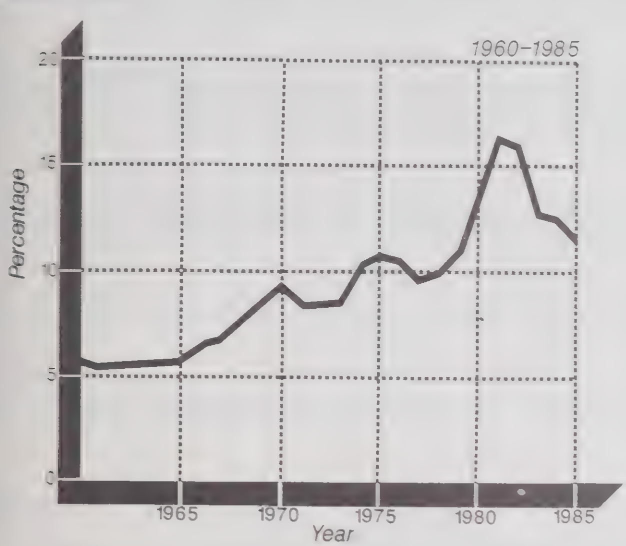


Figure 12

Price Trends in Utility Construction

Base Year 1971

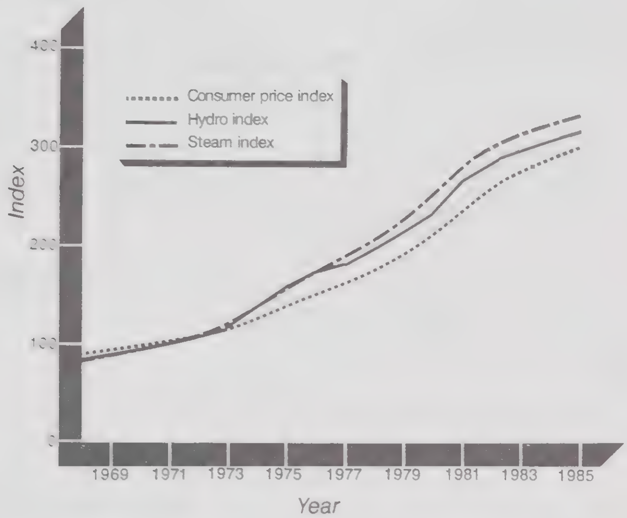


Figure 13

Unit Cost of Fossil Fuel for Electricity Production

1969–1984

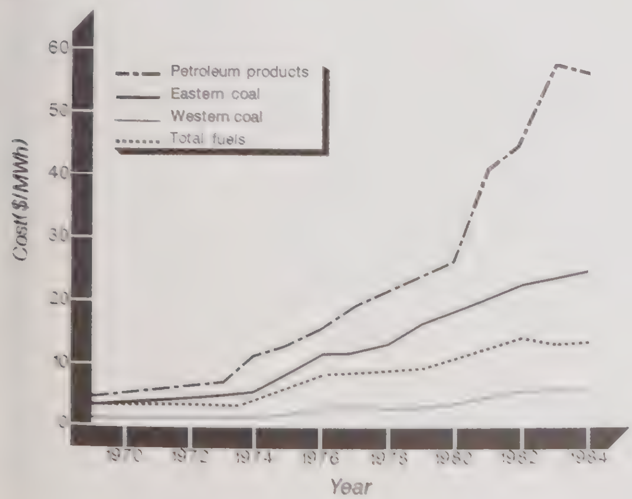
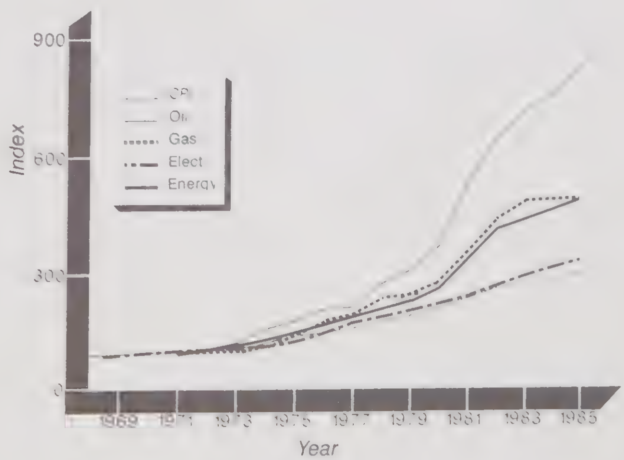


Figure 14

Price Indices

1971–1985



Appendix

Table AI. Installed capacity and electrical energy consumption in Canada, 1920-1985

Year	Installed Capacity: Thermal: Conventional	Installed Capacity: Thermal: Nuclear	Installed Capacity: Thermal: Sub-Total	Installed Capacity: Hydro	Installed Capacity: Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin	Reserve Margin	Load Factor
	(MW)	(MW)	(MW)	(MW)	(MW)	(GWh) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%) (d)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 657	23 049	109 302	12 477	17 264	5 785	34	72
1961	5 072	-	5 072	19 019	24 091	110 950	12 666	18 353	5 738	31	69
1962	5 609	20	5 629	19 338	24 967	116 135	13 257	18 937	6 030	32	70
1963	6 180	20	6 200	20 101	26 301	121 510	13 871	20 783	5 518	27	67
1964	6 694	20	6 714	20 313	27 027	133 949	15 291	22 516	4 511	20	68
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1966	8 307	20	8 327	22 438	30 765	156 956	17 917	25 921	4 844	19	69
1967	9 373	240	9 613	23 353	32 966	165 812	18 928	27 812	5 154	19	68
1968	10 711	240	10 951	24 957	35 908	176 841	20 187	30 300	5 608	19	67
1969	12 321	240	12 561	27 031	39 592	189 522	21 635	32 092	7 500	23	67
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1971	14 504	1 570	16 075	30 601	46 676	212 882	24 302	35 720	10 956	31	68
1972	15 318	2 126	17 444	32 500	49 944	231 557	26 433	38 921	11 023	28	68
1973	17 711	2 400	20 111	34 266	54 376	249 298	28 459	42 699	11 677	27	67
1974	18 085	2 666	20 751	36 779	57 530	266 956	30 747	42 528	15 002	35	72
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 537	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	27 853	5 866	33 719	47 919	81 638	340 069	38 821	59 170	22 464	38	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984r	30 427	9 813	40 240	54 949	95 189	385 516	44 009	67 325	27 864	41	65
1985p	30 493	11 159	41 652	56 295	97 947	406 089	46 357	72 367	25 580	35	64

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81, Statistics Canada Publication. 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr).

(c) Statistics Canada Publication 57-204.

(d) Reserve margin = $\frac{\text{(Installed capacity - Peak demand)}}{\text{Peak demand}}$

(e) Load Factor = Average demand ÷ Peak demand.

p. Preliminary figures. r Revised figures.

Table A2. Installed and proposed generating capacity, 1985 (MW)

	Hydro	Nuclear	Conventional Thermal*	Total	% of Canadian Total
Newfoundland	6 340	-	756	7 096	7.24
Prince Edward Island	-	-	122	122	.12
Nova Scotia	366	-	1 849	2 215	2.26
New Brunswick	903	680	1 896	3 479	3.55
Quebec	25 467	951	1 110	27 528	28.10
Ontario	7 130	9 528	13 843	30 501	31.14
Manitoba	3 641	-	500	4 141	4.23
Saskatchewan	743	-	2 083	2 826	2.89
Alberta	734	-	6 486	7 220	7.37
British Columbia	10 840	-	1 664	12 504	12.77
Yukon	82	-	41	123	.13
Northwest Territories	49	-	143	192	.20
Canada Total					
At December 31, 1985	56 295	11 159	30 493	97 947	100.00
Percent of Total	57.47	11.39	31.13	100.00	
Net Additions					
During 1985	1 345	1 346	68	2 759	
Planned Additions 1986	674	1 346	473	2 493	

* Details provided in Table A3. Conventional thermal includes steam, gas turbine, internal combustion.

Source: Energy, Mines and Resources - Utility Questionnaire.

Table A3. Conventional thermal capacity by principal fuel type. Preliminary figures as of December 31, 1985 (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other*	Total
Nfld.	-	505	-	-	505	170	-	170	81	-	81	-	756	-	-	756
PEI	-	71	-	-	71	41	-	41	11	-	11	-	123	-	-	123
NS	875	793	-	-	1 668	180	-	180	1	-	1	875	974	-	-	1 849
NB	285	1 561	-	22	1 868	23	-	23	5	-	5	285	1 589	-	22	1 896
Que.	-	628	-	10	638	363	-	363	109	-	109	-	1 100	-	10	1 110
Ont.	9 356	2 295	1 365	90	13 106	547	181	728	4	6	10	9 356	2 846	1 552	90	13 844
Man.	419	-	4	23	446	24	-	24	30	-	30	419	54	4	23	500
Sask.	1 772	-	106	43	1 921	-	155	155	6	-	6	1 772	6	261	43	2 082
Alta.	4 479	66	1 264	107	5 916	-	524	524	17	29	46	4 479	83	1 817	107	6 486
BC	-	124	1 038	251	1 413	100	54	154	78	18	96	-	302	1 110	251	1 663
Yukon	-	-	-	-	-	-	-	-	41	-	41	-	41	-	-	41
NWT	-	-	-	-	-	-	-	-	143	-	143	-	143	-	-	143
Canada	17 186	6 043	3 777	546	27 552	1 448	914	2 362	526	53	579	17 186	8 017	4 744	546	30 493

* Mainly wood wastes and black liquor.

Numbers may not add up because of rounding off.

Table A4. Electrical energy production by principal fuel type (GWh)

	Conventional Thermal*							% of Total	% Generated By	
	Coal	Oil	Gas	Total	Nuclear	Hydro	Total	Generation	Utilities	Industry
Newfoundland	0	1 754	0	1 754	0	39 633	41 387	9.27	99.00	1.00
Prince Edward Island	0	2	0	2	0	0	2	.00	100.00	.00
Nova Scotia	5 947	661	0	6 608	0	903	7 511	1.68	94.92	5.08
New Brunswick	1 457	2 280	0	3 737	5 427	2 258	11 422	2.56	94.54	5.46
Quebec	0	150	0	150	3 209	133 368	136 727	30.63	87.07	12.93
Ontario	31 973	13	0	31 986	48 459	41 216	121 661	27.25	96.85	3.15
Manitoba	320	61	0	381	0	22 361	22 742	5.09	99.72	.28
Saskatchewan	9 584	9	282	9 875	0	1 941	11 816	2.65	97.02	2.98
Alberta	30 179	9	1 673	31 861	0	1 392	33 253	7.45	91.58	8.42
British Columbia	0	2 022	0	2 022	0	57 104	59 126	13.24	80.38	19.62
Yukon/NWT	0	205	0	205	0	561	766	.17	96.47	3.53
Canada	79 460	7 166	1 955	88 581	57 095	300 737	446 413	100.00	94.32	5.68

* Estimated values.

Source: Statistics Canada
Energy, Mines and Resources Canada - Utility Questionnaire.

Table A5. Provincial electricity imports and exports (GWh)

Province	Year	Interprovincial Trade Exports	Interprovincial Trade Imports	Interprovincial Trade Net Exports	International Trade Exports	International Trade Imports	International Trade Net Exports	Total Net Exports
Newfoundland	1985	31 837	-	31 837	-	-	-	31 837
	1984r	36 043	-	36 043	-	-	-	36 043
	1983	31 234	-	31 234	-	-	-	31 234
Prince Edward Island	1985	-	575	-575	-	-	-	-575
	1984r	-	539	-539	-	-	-	-539
	1983	-	519	-519	-	-	-	-519
Nova Scotia	1985	199	350	-151	-	-	-	-151
	1984r	282	301	-19	-	-	-	-19
	1983	121	723	-602	-	-	-	-602
New Brunswick	1985	927	6 026	-5 099	6 093	12	6 081	982
	1984r	841	4 588	-3 747	5 657	17	5 640	1 893
	1983	1 245	4 112	-2 867	5 265	24	5 241	2 374
Quebec	1985	14 491	31 878	-17 387	9 581	3	9 578	-7 809
	1984r	11 668	36 105	-24 437	11 250	8	11 242	-13 195
	1983	9 371	31 290	-21 919	10 128	8	10 120	-11 799
Ontario	1985	44	9 632	-9 588	10 563	1 701	8 862	-726
	1984r	64	8 302	-8 238	11 370	913	10 457	2 219
	1983	59	6 336	-6 277	12 207	369	11 838	5 561
Manitoba	1985	2 524	1 238	1 286	5 660	45	5 615	6 901
	1984r	2 565	1 301	1 264	5 057	43	5 014	6 278
	1983	2 555	1 213	1 342	5 994	19	5 975	7 317

.../2

Table A5. Provincial electricity imports and exports (GWh) (Continued)

Province	Year	Interprovincial Trade			International Trade			Total Net
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	Exports
Saskatchewan	1985	1 236	1 556	-320	163	93	70	-250
	1984r	1 302	1 625	-323	86	66	20	-303
	1983	1 210	1 601	-391	81	84	-3	-394
Alberta	1985	243	278	-35	-	2	-2	-37
	1984r	262	302	-40	-	2	-2	-42
	1983	198	346	-148	-	2	-2	-150
British Columbia	1985	275	243	32	10 956	837	10 119	10 151
	1984r	298	262	36	8 015	1 294	6 721	6 757
	1983	341	196	145	4 633	2 251	2 382	2 527
Yukon	1985	-	-	-	-	-	-	-
	1984r	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
Northwest Territories	1985	-	-	-	-	-	-	-
	1984r	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
Canada	1985	-	-	-	43 016	2 693*	40 323	40 323
	1984r	-	-	-	41 436	2 343*	39 093	39 093
	1983	-	-	-	38 308	2 757*	35 551	35 551

r Revised.
* Includes exchanges.

Source: Statistics Canada.

Table A6. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1984	504.60	170.39	81.07	-	756.06	6 212.70	6 968.76
Additions 1985	-	-	-	-	-	127.31	127.31
Total end 1985	504.60	170.39	81.07	-	756.06	6 340.01	7 096.07
Additions proposed							
1986	-	-	-	-	-	.51	.51
1989	-	-	-	-	-	5.00	5.00
Total end 1986	504.60	170.39	81.07	-	756.06	6 345.52	7 101.58
PRINCE EDWARD ISLAND							
Total end 1984	70.50	40.85	11.14	-	122.49	-	122.49
Additions 1985	-	-	-	-	-	-	-
Total end 1985	70.50	40.85	11.14	-	122.49	-	122.49
NOVA SCOTIA							
Total end 1984	1 783.09	205.00	0.60	-	1 988.69	366.40	2 355.09
Additions 1985	-114.51	-24.99	-	-	-139.50	-	-139.50
Total end 1985	1 668.58	180.01	0.60	-	1 849.19	366.40	2 215.59
Additions proposed							
1991	300.00	-	-	-	300.00	-	300.00
1995	300.00	-	-	-	300.00	-	300.00
1996	300.00	-	-	-	300.00	-	300.00
1988	300.00	-	-	-	300.00	-	300.00
2000	300.00	-	-	-	300.00	-	300.00
2002	300.00	-	-	-	300.00	-	300.00
2003	300.00	-	-	-	300.00	-	300.00
2005	300.00	-	-	-	300.00	-	300.00
Total end 2005	4 068.58	180.01	0.60	-	4 249.19	366.40	4 615.59

.../2

Table A6. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEW BRUNSWICK							
Total end 1984	1 868.08	23.38	4.84	680.00	2 576.30	903.03	3 479.33
Additions 1985	-	-	-	-	-	-	-
Total end 1985	1 868.08	23.38	4.84	680.00	2 576.30	903.03	3 479.33
Additions proposed							
1992	200.00	-	-	-	200.00	-	200.00
1996	335.00	-	-	-	335.00	-	335.00
Total end 1996	2 403.08	23.38	4.84	680.00	3 111.30	903.03	4 014.33
QUEBEC							
Total End 1984	637.75	362.88	108.85	951.40	2 060.88	24 877.52	26 938.40
Additions 1985	-	-	-	-	0.0	589.00	589.00
Total End 1985	637.75	362.88	108.85	951.40	2 060.88	25 466.52	27 527.40
Additions Proposed							
1986	-	-	-	-	.00	589.00	589.00
1987	-	-	-	-	.00	-	.00
1988	-	-	-	-	.00	21.60	21.60
1989	-	-	-	-	.00	980.00	980.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	-	.00	-	.00
1992	-	-	-	-	.00	950.00	950.00
1993	-	-	-	-	.00	950.00	950.00
1994	-	-	-	-	.00	-	.00
1995	-	700.00	-	-	700.00	-	700.00
1996	-	700.00	-	-	700.00	-	700.00
1997	-	100.00	-	-	100.00	684.00	784.00
1998	-	100.00	-	-	100.00	684.00	784.00
1999	-	700.00	-	-	700.00	-	700.00
Total End 1999	637.75	2 662.88	108.85	951.40	4 360.88	30 325.12	34 686.00

.../3

Table A6. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ONTARIO							
Total end 1984	12 899.80	728.09	9.52	8 182.00	21 819.41	7 129.95	28 949.36
Additions 1985	206.00	-	-	1 346.00	1 552.00	-	1 552.00
Total end 1985	13 105.80	728.09	9.52	9 528.00	23 371.41	7 129.95	30 501.36
Additions proposed							
1986	-	104.00	-	1 346.00	1 450.00	-	1 450.00
1987	-	-	-	830.00	830.00	-	830.00
1988	-	-	-	881.00	881.00	7.50	888.50
1989	-	-	-	881.00	881.00	20.50	901.50
1990	-	-	-	-	-	15.00	15.00
1991	-	-	-	881.00	881.00	-	881.00
1992	-	-	-	881.00	881.00	-	881.00
Total end 1992	13 105.80	832.09	9.52	15 228.00	29 175.41	7 172.95	36 348.36
MANITOBA							
Total end 1984	445.80	23.80	30.48	-	500.08	3 641.10	4 141.18
Additions 1985	-	-	-	-	-	-	-
Total end 1985	445.80	23.80	30.48	-	500.08	3 641.10	4 141.18
Additions proposed							
1990	-	-	-	-	-	256.00	256.00
1991	-	-	-	-	-	640.00	640.00
1992	-	-	-	-	-	384.00	384.00
1997	-	-	-	-	-	130.00	130.00
1998	-	-	-	-	-	520.00	520.00
1999	-	-	-	-	-	650.00	650.00
Total end 1999	445.80	23.80	30.48	-	500.08	6 221.10	6 721.18

.../4

Table A6. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
SASKATCHEWAN							
Total end 1984	1 921.76	154.92	6.10	-	2 082.78	575.50	2 658.28
Additions 1985	-	-	-	-	-	168.00	168.00
Total end 1985	1 921.76	154.92	6.10	-	2 082.78	743.50	2 826.28
Additions proposed							
1986	-	-	-	-	-	84.00	84.00
Total end 1986	1 921.76	154.92	6.10	-	2 082.78	827.50	2 910.28
ALBERTA							
Total end 1984	5 915.72	524.10	46.28	-	6 486.10	733.70	7 219.80
Additions 1985	-	-	-	-	-	-	-
Total end 1985	5 915.72	524.10	46.28	-	6 486.10	733.70	7 219.80
Additions proposed							
1986	380.00	-	-	-	380.00	-	380.00
1989	400.00	-	-	-	400.00	-	400.00
1990	380.00	-	-	-	380.00	-	380.00
1991	400.00	-	-	-	400.00	-	400.00
1993	-	200.00	-	-	200.00	-	200.00
1994	-	300.00	-	-	300.00	-	300.00
1995	360.00	-	-	-	360.00	-	360.00
1996	-	-	-	-	-	759.00	759.00
1997	360.00	-	-	-	360.00	906.00	1 266.00
1998	-	-	-	-	-	151.00	151.00
1999	360.00	-	-	-	360.00	-	360.00
2000	360.00	200.00	-	-	560.00	-	560.00
2001	360.00	-	-	-	360.00	-	360.00
2002	-	-	-	-	-	-	-
2003	1 080.00	400.00	-	-	1 480.00	-	1 480.00
2004	-	100.00	-	-	100.00	-	100.00
2005	360.00	-	-	-	360.00	-	360.00
Total end 2005	10 715.72	1 724.10	46.28	-	12 486.10	2 549.70	15 035.80

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Table A6. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
BRITISH COLUMBIA							
Total end 1984	1 414.42	153.70	95.93	-	1 664.05	10 378.79	12 042.84
Additions 1985	-	-	-	-	-	460.75	460.75
Total end 1985	1 414.42	153.70	95.93	-	1 664.05	10 839.54	12 503.59
Additions proposed							
1997	-	-	-	-	-	160.00	160.00
1998	-	-	-	-	-	80.00	80.00
2000	-	-	-	-	-	300.00	300.00
2001	-	-	-	-	-	600.00	600.00
2002	-	-	-	-	-	110.00	110.00
2003	-	-	-	-	-	110.00	110.00
2004	-	-	-	-	-	55.00	55.00
Total end 2004	1 414.42	153.70	95.93	-	1 664.05	12 254.54	13 918.59
YUKON and N.W.T.							
Total end 1984	-	-	182.52	-	182.52	130.70	313.22
Additions 1985	-	-	1.50	-	1.50	-	1.50
Total end 1985	-	-	184.02	-	184.02	130.70	314.72
Additions proposed							
1986	-	-	3.00	-	-	-	.00
Total end 1986	-	-	187.02	-	184.02	130.70	314.72

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Table A6. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total End 1984	27 461.52	2 387.11	577.33	9 813.40	40 239.36	54 949.39	95 188.75
Additions 1984	91.49	-24.99	1.54	1 346.00	1 414.04	1 345.06	2 759.10
Total End 1985	27 553.01	2 362.12	578.87	11 159.40	41 653.40	56 294.45	97 947.85
Additions Proposed							
1986	380.00	104.00	3.00	1 346.00	1 830.00	673.51	2 503.51
1987	.00	.00	.00	830.00	830.00	.00	830.00
1988	.00	.00	.00	881.00	881.00	29.10	910.10
1989	400.00	.00	.00	881.00	1 281.00	1 005.50	2 286.50
1990	380.00	.00	.00	.00	380.00	271.00	651.00
1991	700.00	.00	.00	881.00	1 581.00	640.00	2 221.00
1992	200.00	.00	.00	881.00	1 081.00	1 334.00	2 415.00
1993	.00	200.00	.00	.00	200.00	950.00	1 150.00
1994	.00	300.00	.00	.00	300.00	.00	300.00
1995	660.00	700.00	.00	.00	1 360.00	.00	1 360.00
1996	635.00	700.00	.00	.00	1 335.00	759.00	2 094.00
1997	360.00	100.00	.00	.00	460.00	1 880.00	2 340.00
1998	300.00	100.00	.00	.00	400.00	1 435.00	1 835.00
1999	360.00	700.00	.00	.00	1 060.00	650.00	1 710.00
2000	660.00	200.00	.00	.00	860.00	300.00	1 160.00
2001	360.00	.00	.00	.00	360.00	600.00	960.00
2002	300.00	.00	.00	.00	300.00	110.00	410.00
2003	1 380.00	400.00	.00	.00	1 780.00	110.00	1 890.00
2004	.00	100.00	.00	.00	100.00	55.00	155.00
2005	660.00	.00	.00	.00	660.00	.00	660.00
Total End 2005	35 288.01	5 966.12	581.87	16 859.40	58 692.40	67 096.56	125 788.96

Source: Energy, Mines and Resources - Utility Questionnaire.

Table A7. Installed generating capacity expansion in Canada by station. Major 1985 additions and 1986 - 2005 projections

Province and Station	Type*	Additions in 1985 (MW)	Year	Additions Proposed (MW)	Status*	Proposed Plant Capacity (MW)
NEWFOUNDLAND						
Unknown location	H		1989	5.0	P	5.00
Cat Arm	H	127.0			I	127.00
Petty Harbour	H		1986	1 x 0.51	C	5.51
Tors Cove	H	.25			I	6.75
Port Union	H	.06				.62
NOVA SCOTIA						
Lingan	S(c)		1996	300	P	900.00
Fall River	H	0.5		-	I	0.50
New Thermal	S(c)		1998	300	P	
			2000	300	P	
			2002	300	P	
			2003	300	P	
			2005	300	P	1 500.00
Point Tupper	S(c)		1991	300	P	
			1995	300	P	
NEW BRUNSWICK						
New Steam	S(c)		1992	200	P	
			1996	335	P	535.00
QUEBEC						
LG-4	H	2 x 294.5			I	
			1986	2 x 294.5	I*	2 650.50
Lac Robertson	H		1988	2 x 10.8	P	21.60
Manic 5A	H		1989	4 x 245.0	P	2 272.00
LG-2A	H		1992	2 x 317	P	
			1992	316	P	
			1993	316	P	
			1993	2 x 317	P	7 228.00
LG-1	H		1997	6 x 114	P	
			1998	6 x 114	P	1 368.00
Various locations	GT(o)		1995	700	P	
			1996	700	P	
			1997	100	P	
			1998	100	P	
			1999	700	P	2 300.00

Table A7. Installed generating capacity expansion in Canada by station. Major 1985 additions and 1986 - 2005 projections (Continued)

Province and Station	Type*	Additions in 1985	Year	Additions Proposed	Status*	Proposed Plant Capacity
		(MW)		(MW)		(MW)
ONTARIO						
Atikokan	S(C)	206			I	
Bruce B	N	830			I	
			1986	830	C	
			1987	830	C	3 320.00
Darlington	N		1988	881	C	
			1989	881	C	
			1991	881	C	
			1992	881	C	
	GT		1986	4 x 26	P	3 628.00
Magpie	H		1988	7.5	P	
			1989	7.5	P	
			1989	2 x 6.5	P	
			1990	2 x 7.5	P	43.00
Pickering B	N	516			I	
			1986	516	C	2 064.00
MANITOBA						
Limestone	H		1990	2 x 128	C	
			1991	5 x 128	C	
			1992	3 x 128	C	1 280.00
Wuskwatim	H		2012	87.5	P	
			2013	3 x 87.5	P	350.00
Conawapa	H		1997	130	P	
			1998	4 x 130	P	
			1999	5 x 130	P	1 300.00
SASKATCHEWAN						
Nipawin	H	168			I	
			1986	84	C	252.00

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Table A7. Installed generating capacity expansion in Canada by station. Major 1985 additions and 1986 - 2005 projections (Continued)

Province and Station	Type*	Additions in 1985	Year	Additions Proposed	Status*	Proposed Plant Capacity
		(MW)		(MW)		(MW)
ALBERTA						
Genesee	S(c)		1989	400	C	
			1991	400	C	800.00
Sheerness	S(c)		1986	380	C	
			1990	380	C	760.00
Slave River	H		1996	2 x 153	P	-
			1996	3 x 151	P	-
			1997	6 x 151	P	-
			1998	151	P	1 816.00
New Steam	S(c)		1995	360	P	-
			1997	360	P	-
			1999	360	P	
			2000	360	P	
			2001	360	P	
			2003	3 x 360	P	
			2005	360	P	
					P	3 240.00
Peak Gas	GT		1993	2 x 100	P	
			1994	3 x 100	P	
			2000	2 x 100	P	
			2003	4 x 100	P	
			2004	100	P	1 200.00
BRITISH COLUMBIA						
Keenleyside	H		1997	2 x 80	P	
			1998	1 x 80	P	240.00
Murphy Creek	H		2002	2 x 55	P	
			2003	2 x 55	P	275.00
			2004	55	P	
Revelstoke	H	460.75			I	
					I	1 843.00
Peace Site C	H		2000	2 x 150	P	
			2001	4 x 150	P	900.00

Table A7. Installed generating capacity expansion in Canada by station. Major 1985 additions and 1986 - 2005 projections (Continued)

Province and Station	Type*	Additions in 1985 (MW)	Year	Additions Proposed (MW)	Status*	Proposed Plant Capacity (MW)
YUKON						
Watson Lake	IC	1.5			I	5.05
NORTHWEST TERRITORIES						
Hay River	IC		1986	3	P	

* Legend

H	Hydro	IC	Internal combustion
S(c)	Steam (coal)	GT	Gas turbine
N	Nuclear	I	Installed
P	Planned	C	Under construction
GT(o)	Gas turbine (oil)	I*	Installed but testing

Source: Energy, Mines and Resources Canada - Utility Questionnaire.

DEFINITIONS AND ABBREVIATIONS

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gasses or steam produced by burning fossil fuels.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kWh). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Power: Electric power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GWh): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP): The total value of production of goods and services measured at market prices.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy: Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power. 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100 watt light bulbs.

Kilowatt hour (kWh): The commercial unit of electric energy. 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100 watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power. 1000 kilowatts.

Megawatt hour (MWh): A unit of bulk energy. 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil, or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: first, in case of unexpected breakdown of generating equipment; second, in case the actual peak load is higher than forecast.

Terawatt Hours (TWh): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

Energy, Mines and Resources Canada

Énergie, Mines et Ressources Canada

Hon. Marcel Masse, Minister

L'Hon. Marcel Masse, Ministre

ELECTRIC POWER IN CANADA 1986

Canada

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From TransAlta Utilities' system control centre, the company monitors the operation of its 68 000 km of transmission and distribution lines. The centre also allows for the dispatch of electrical energy from the company's 13 hydroelectric and three coal-fired plants.

The Electric Power Industry in Canada

INDUSTRY STRUCTURE

Under the Canadian Constitution, electricity is primarily within the jurisdiction of the provinces. As a consequence, Canada's electrical industry is organized along provincial lines. In most provinces, the industry is highly integrated, with the bulk of the generation, transmission, and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1.

Among the major electric utilities, eight are provincially owned, four are investor-owned, two are municipally owned, and one is a federal Crown corporation. In 1986, provincial electric utilities owned about 84 per cent of total installed generating capacity and produced about 84 per cent of total generated electricity. The four investor-owned utilities accounted for 6 per cent of all Canadian electric utility capacity and produced about 7 per cent of total energy. Municipally owned utilities in Manitoba and Alberta accounted for 1.2 per cent of capacity ownership, but produced only 0.3 per cent of total generated electricity. The federal government plays an insignificant role in capacity ownership and generation in Canada. Although the federally owned Northern Canada Power Commission generates and distributes most of the electricity supplied in the Yukon and Northwest Territories, in 1986 it accounted for only 0.3 per cent of total Canadian capacity ownership and 0.2 per cent of total Canadian generation.

In addition to the 15 major electric utilities, there are about 63 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining, and aluminum smelting sectors. In 1986, industrial establishments owned about 6.4 per cent of total capacity and produced about 8 per cent of total generated electricity in Canada, as shown in Table 1.2. Since 1970, the shares of capacity and production by industrial

Table 1.1. Canada's major electric utilities

Province	Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Co. Ltd.	Private
Prince Edward Island	Maritime Electric Co. Ltd.	Private
Nova Scotia	Nova Scotia Power Corporation	Provincial
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	Manitoba Hydro	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Ltd.	Private
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Private
British Columbia	British Columbia Hydro and Power Authority	Provincial
*Yukon**	Northern Canada Power Commission	Federal
Northwest Territories	Northern Canada Power Commission	Federal

** On March 31, 1987, the Yukon assets of the Northern Canada Power Commission were transferred from the federal government to the Yukon government. This change of ownership is not reflected in the text.*

Source: Energy, Mines and Resources Canada.

establishments have been reduced by half. Most of Canada's electrical capacity and generation is now supplied by the large provincial utilities.

In addition to the major electric utilities and industrial establishments, there are about 24 minor utilities also producing electricity. Half of these are owned by investors and the other half by municipalities. In 1986, the minor utilities accounted for 2.1 per cent of total capacity, but produced only 0.5 per cent of electrical energy.

ELECTRICITY AND THE ECONOMY

The electric power industry is a significant presence within the Canadian economy. As indicated in Table 1.3, there were about 76 000 people directly employed by the industry in 1985, about 0.7 per cent of total Canadian employment.

Total revenue increased to about \$16 billion in 1985 from \$14 billion in 1984, an increase of 14 per cent. Of this total, approximately \$1.4 billion or 9 per cent came from export earnings. The electric power industry has steadily increased its contribution to the nation's Gross Domestic Product, from 2.7 per cent in 1980, to 3.2 per cent in 1984, and 3.5 per cent in 1985.

Total assets of the industry were about \$87 billion in 1985. Ontario Hydro, Hydro-Québec, and BC Hydro are the three largest electric utilities in Canada and rank first, second, and fifth respectively, in terms of assets, among all Canadian companies.

CANADIAN ELECTRIC UTILITIES

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH).

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. Approximately 89 per cent of the company's power supply is purchased from NLH, with the balance generated by its own power stations. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited, and Union Electric Light and Power Company. Through its predecessors, the company's service dates back to 1885.

NLH is a provincial Crown corporation concerned primarily with electricity generation. It was incorporated in 1975 and is the parent company of a group that includes Churchill Falls (Labrador)

Table 1.2. Electrical capacity and production by utilities and industrial establishments, 1970-1986

	Installed Generating Capacity		Energy Production	
Year	Utilities	Industrial Establishments	Utilities	Industrial Establishments
		(per cent)		
1970	88	12	84	16
1975	90	10	87	13
1980	92	8	89	11
1981	92	8	90	10
1982	93	7	90	10
1983	93	7	90	10
1984	93	7	91	9
1985	93	7	92	8
1986	94	6	92	8

Source: *Electric Power Statistics, Volume II, Statistics Canada, 57-202, 57-001.*

Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), and Twin Falls Power Corporation Limited. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. On behalf of the province, NLH also administers the activities of the Power Distribution District of Newfoundland and Labrador, which supplies energy to rural customers. Together, NLPC and NLH serve about 200 000 customers.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned electric utility which has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation and transmission of electricity throughout the island. MECL operates two oil-fired generating plants on the island at Charlottetown and Borden, which are for standby purposes only. It has a 10 per cent equity interest in New Brunswick Electric Power Commission's dual-fuel, coal/oil-fired No. 2 unit located in Dalhousie, N.B., and leases from the P.E.I. government the submarine cable interconnection that connects the island to New Brunswick. MECL currently purchases 98 per cent of its electricity requirements from New Brunswick Power.

Table 1.3. Electric utility assets, revenue and employees, 1985

Utility	Assets	Revenue	Employees
	($ millions)		(persons)
Newfoundland and Labrador Hydro	2 104	331	1 196
Newfoundland Light & Power Co. Ltd.	353	244	938
Maritime Electric Co. Ltd.	86	64	201
Nova Scotia Power Corporation	1 414	492	2 450
New Brunswick Electric Power Commission	2 870	894	2 500
Hydro-Québec	29 183	4 492	18 208
Ontario Hydro	29 320	4 625	31 166
Manitoba Hydro	3 129	553	3 853
City of Winnipeg Hydro-Electric System	132	80	730
*Saskatchewan Power Corporation**	2 150	837	3 064
TransAlta Utilities	3 736	836	2 496
Edmonton Power	835	263	851
Alberta Power Ltd.	1 014	324	1 340
*BC Hydro and Power Authority**	10 472	2 094	6 508
Northern Canada Power Commission	276	89	330
Canada	87 074	16 218	75 831

** Includes natural gas operations.*

Source: Electric utilities' annual reports.

MECL is the major distributor on the island, serving about 44 100 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

In 1972, the Nova Scotia Power Corporation bought the shares of the investor-owned Nova Scotia Light and Power Co. Ltd. and in 1973 was incorporated as the present Nova Scotia Power Corporation (NSPC), serving all of the province. NSPC generates most of its electricity from thermal energy, with more than half of the production coming from coal. The corporation also maintains hydro-generation facilities and purchases power from New Brunswick. The largest portion of the total production of the province is derived from the Lingan generating station located on Cape Breton Island. In 1986, NSPC served about 350 000 customers.

New Brunswick

Prior to 1918, more than 20 organizations in New Brunswick, both public and private, were in the business of generating and distributing electricity. In 1918, the government of the day passed an Order-in-Council setting up a water power commission to determine the water power resources of the province. Acting on the recommendation of the commission, the New Brunswick Electric Power Commission (NB Power) was established by an Act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. Electricity is generated from a balance of nuclear, hydro, and thermal sources, and the utility also makes purchases from Quebec. NB Power directly provides electricity to 241 000 customers and indirectly serves an additional 38 000 customers through sales to municipal utilities.

Quebec

Hydro-Québec was established by the provincial Legislative Assembly in 1944. After its creation, Hydro-Québec acquired the assets of Montreal Light, Heat and Power Consolidated and Beauharnois Light, Heat and Power Company. In 1963, Hydro-Québec acquired the remaining 10 privately owned power companies in the province, including the Shawinigan Water and Power Company, Southern Power Company Limited, Québec Power Company, and Gatineau Power Company. Several municipal distribution and public lighting systems were also acquired, together with almost all the electricity cooperatives in Quebec.

Hydro-Québec has three wholly owned, active subsidiaries: the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande Complex; Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; and Cedars Rapids Transmission Company Limited, which transmits export power to New York State. Hydro-Québec is also a shareholder in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant, and in Nouveler Inc., which promotes energy efficiency and alternative energy sources.

Currently, Hydro-Québec serves more than 2.6 million customers and is responsible for the generation, transmission, and distribution of most of the electricity sold in Quebec. Almost all of the electricity generated by Hydro-Québec is from hydraulic sources.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by the provincial legislature. It has broad powers to produce, buy, and deliver electric power throughout the province and currently operates under the Power Corporation Act. The main responsibility of Ontario Hydro is to provide power to the province's 316 municipal utilities, which in turn distribute power to their own customers. In addition, Ontario Hydro supplies about 100 major industrial users directly and about 780 000 rural retail customers in areas or communities not served by municipal utilities. Electricity is generated from a balance of thermal, nuclear, and hydro sources. In 1986, more than three million customers were served by Ontario Hydro and the municipal utilities in the province.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the Manitoba Hydro Act. It distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1986, Manitoba Hydro served about 341 000 customers directly. Almost all of the electricity produced in the province is derived from hydraulic sources.

Saskatchewan

The Saskatchewan Power Corporation (SPC) was established as a Crown corporation under the 1950 Power Corporation Act. It replaced the Saskatchewan Power Commission, created in 1929 to develop an integrated provincial electrical system. Under the Power Corporation Act, the mandate of SPC includes the generation, transmission, and distribution of natural gas and electricity. At the end of 1986, the corporation served about 390 000 customers

with electricity and 260 000 customers with natural gas. The bulk of the electricity produced is from thermal sources.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 91 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 9 per cent of Alberta's electrical energy is supplied by industry.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company has been engaged in the production and distribution of electricity in the Province of Alberta since its incorporation in 1911. About 75 per cent of the electrical energy requirements of Alberta are supplied by the company, to over half of the population. In 1986, over 283 000 customers were served directly.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. Alberta Power supplied about 16 per cent of the total Alberta electricity requirements in 1986, serving over 147 000 customers.

Edmonton Power is Alberta's second largest electric utility and is the largest municipally owned utility in Canada, in terms of generating capacity. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. Although the utility produced only 0.4 per cent of the electricity requirements of Alberta, it had a 15 per cent share of the total provincial market in 1986, serving more than 225 000 customers. Edmonton Power purchases most of its electricity from TransAlta Utilities and Alberta Power.

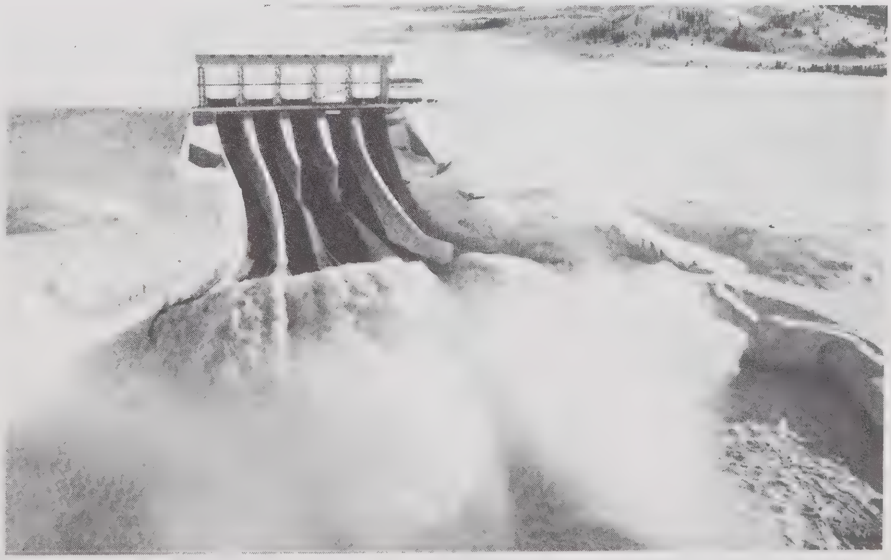
British Columbia

British Columbia Hydro & Power Authority (BC Hydro), incorporated in 1961, is a Crown corporation operating in British Columbia. BC Hydro provides electrical service throughout the province, with the exception of the area served by Cominco Limited and its subsidiary, West Kootenay Power and Light Company Limited. BC Hydro is the third largest electric utility in Canada and the largest distributor of natural gas in British Columbia. BC Hydro generates, transmits, and distributes electricity to more than one million customers in a service area which contains more than 90 per cent of the population of the province. It distributes natural gas in Greater Vancouver and in the Fraser Valley, and propane-air gas in Greater Victoria. BC Hydro also operates a railway offering local and terminal freight service in Greater Vancouver and the Fraser Valley.

Yukon and Northwest Territories

The Northern Canada Power Commission (NCPC) is a federal Crown corporation, supplying electricity in the Yukon and Northwest Territories. The NCPC was created in 1956 and operates under the authority of the Northern Canada Power Commission Act.

In 1948, the Northwest Territories Power Commission was established as a federal agency to operate a hydroelectric station near Yellowknife. In 1956, the Commission's mandate was expanded and it began to take over generating facilities operated by various federal departments and to build additional facilities. At the same time, its name was changed to the Northern Canada Power Commission. NCPC now operates 50 separate power systems throughout the territories and in 1986 served approximately 12 400 customers. NCPC also supplies electricity to Field, British Columbia, because the town is located within a federal park.



Surplus water is discharged through the five gates of Hydro-Québec's La Grande 2 spillway. The water is projected scores of metres into the air, dissipating part of its energy before it falls.

Canadian Electricity in the International Context

Canada has the second largest area of any country in the world. It has abundant natural resources, particularly rivers suitable for hydroelectric power. Canada is also one of the largest electricity producers in the world. This chapter compares Canada's electric supply and demand with those of selected other countries.

Installed Generating Capacity

At the end of 1985, total world electrical generating capacity was approximately 2 376 GW. A breakdown of capacity by fuel type for the top 20 countries is shown in Table 2.1. Of the world total, conventional thermal accounted for 1 610 GW (68 per cent); hydro 552 GW (23 per cent); and nuclear 214 GW (9 per cent).

The U.S. electric power industry was the largest in the world with a total generating capacity of 686 GW. The U.S.S.R. was second, with generating capacity of 315 GW; Japan was third with 154 GW; and West Germany was fourth with 98 GW. The United States lead in installed capacity for every fuel type. U.S. conventional thermal accounted for more than 32 per cent of the world's thermal capacity; hydro for 15 per cent; and nuclear for 37 per cent.

Canada ranked fifth in the world with a generating capacity of about 97 GW, accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and U.S.S.R.; Canada's nuclear capacity is sixth in the world and its conventional thermal capacity is ninth.

France's nuclear industry is the most developed in Europe. In 1985, it had the second largest nuclear capacity in the world, with a total of 37.5 GW. As a percentage of total domestic electrical capacity, France's nuclear capacity was the largest at 43 per cent.

Electricity Generation

During 1985, a total of 9 422 TW.h of electricity was generated around the world. Of this total, conventional thermal, mainly from coal-fired stations, accounted for 5 997 TW.h (64 per cent); hydro 1 973 TW.h (21 per cent); and nuclear 1 452 TW.h (15 per cent). Although nuclear accounted for only 9 per cent of the world total generating capacity in 1985, its energy production share was 15 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants.

Table 2.1. International comparison of installed generating capacity, 1985

Country	Conventional Thermal	Hydro	Nuclear	Total
		(MW)		
United States	521 503	84 397	80 100	686 000
U.S.S.R.	215 000	61 000	29 000	315 000
Japan	99 408	33 966	20 726	154 100
West Germany	74 456	6 661	16 938	98 055
Canada	30 885	56 048	9 813	96 746
France	27 500	22 000	37 500	87 000
China	57 840	27 160	0	85 000
United Kingdom	52 711	4 189	7 100	64 000
Italy	37 357	17 343	1 300	56 000
India	34 239	16 298	1 095	51 626
Brazil	6 138	36 924	626	43 688
Spain	22 520	13 180	5 700	41 400
Australia	26 516	7 084	0	33 600
Sweden	8 150	15 450	9 500	33 100
Poland	26 892	2 007	0	28 899
South Africa	23 223	572	965	24 760
Mexico	17 642	6 621	0	24 263
Norway	249	23 551	0	23 800
East Germany	18 667	1 851	1 830	22 348
Czechoslovakia	15 146	2 929	1 760	19 835
World Total	1 609 673	552 144	214 183	2 376 000
	(68%)	(23%)	(9%)	(100%)

Source: Energy, Mines and Resources Canada.

Generation by fuel type for the world's top 20 producers is shown in Table 2.2.

About 26 per cent of total world electricity generation took place in the United States in 1985. Its conventional thermal generation was 1 805 TW.h, accounting for 30 per cent of the world conventional thermal total.

Canada was the largest hydro-electric energy producer in the world in 1985 with 301 TW.h, accounting for about 15 per cent of total hydro production. Canada's total production ranked fourth in the world, next to the United States, the U.S.S.R., and Japan, with total production of 446 TW.h, or 5 per cent of the world total.

The United States was the largest nuclear energy producer in the world in 1985, with a total of 384 TW.h or 26 per cent of the world nuclear total. As a proportion of total national electricity production, however, France's nuclear generation was the highest at about 65 per cent. Although Belgium was not among the top 20 electricity producers, its nuclear proportion was the second highest at 60 per cent. Sweden ranked third with a nuclear proportion of 42 per cent. Canada's nuclear share was a relatively small 13 per cent. The nuclear shares in the United States and the U.S.S.R. were 16 per cent and 11 per cent respectively.

Domestic Electricity Consumption

In 1985, Norway consumed 21 950 kW.h of electricity per capita, more than any other country in the world. Canada was the second largest per capita electricity user, at 16 485 kW.h.

Table 2.3 reports electricity consumption per capita in 1985 for 23 countries. The first 10 countries are listed according to their actual global rankings. The second group of countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true rankings in the world.

As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed more than 11 times the world average; Canada, Iceland, and Sweden more than eight times; and the United States about five times. Nigeria's and India's per capita consumption levels were less than 10 per cent of the world average. Although China was the fifth largest electrical energy producer in the world, its per capita

Table 2.2. International comparison of electricity generation by fuel type, 1985

Country	Conventional Thermal	Hydro	Nuclear	Total
		(TW.h)		
United States	1 805	281	384	2 470
U.S.S.R.	1 170	205	170	1 545
Japan	365	82	151	598
Canada	88	301	57	446
China	314	93	0	407
West Germany	248	17	120	384
France	56	59	214	329
United Kingdom	202	4	61	267
Brazil	8	194	3	205
Italy	126	44	7	177
India	110	55	5	170
South Africa	134	1	6	141
Poland	134	4	0	138
Sweden	6	70	56	132
Spain	66	33	28	127
Australia	108	14	0	122
East Germany	100	2	12	114
Norway	0	103	0	103
Mexico	67	26	0	93
Czechoslovakia	64	4	12	80
World Total	5 997 (64%)	1 973 (21%)	1 452 (15%)	9 422 (100%)

Source: Energy, Mines and Resources Canada.

consumption was only 18 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economic hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much energy being used for space-heating purposes.

Total Electricity Consumption Growth

World electricity consumption grew by approximately 4.1 per cent annually between 1983 and 1985. Table 2.4 reports total electricity consumption growth rates during the period 1983-85 for 25 selected countries around the world. In general, most of the countries with high consumption growth rates were developing countries. This was largely due to the fact that many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Canada was one of the few developed countries with a high electricity consumption growth rate during the period 1983-85. Its average growth rate was 5.6 per cent, compared with 4.9 per cent for France, 4.8 per cent for Japan, 3.5 per cent for the U.S., 3.4 per cent for West Germany, and 2.0 per cent for the United Kingdom. The world average during the same period was 4.1 per cent. The United Kingdom, Italy, and Nigeria were among the countries with the lowest consumption growth rates in the world.

Electricity Intensities

Table 2.5 compares the intensity of electricity use in the economies of selected industrialized countries. Electricity intensity is defined as total electricity consumption per dollar of Gross Domestic Product (GDP). To facilitate the comparison, all currencies were converted into U.S. dollars at 1980 prices and exchange rates. Because of the limited availability of data, only 12 countries are included in the table. Among these countries, Canada had the highest electricity intensity.

Canada's electricity intensity grew by approximately 10.5 per cent between 1975 and 1985. France also experienced a large increase in electricity intensity during this decade, with a 33 per cent change. In Japan and the United Kingdom there were reductions of 17.5 per cent and 14.5 per cent respectively. In the United States, electricity intensity grew slightly between 1975 and 1980, before declining again to its 1975 level in 1985.

Table 2.3. International comparison of per capita electricity consumption, 1985

Country	kW.h/person	As Percentage of World Average
Norway	21 950	1 127
Canada	16 485	846
Iceland	15 833	813
Sweden	15 661	804
Qatar	11 415	586
Luxembourg	10 811	555
Finland	9 998	513
United States	9 652	496
New Zealand	8 708	447
Australia	7 727	397
East Germany	6 839	351
West Germany	5 666	291
U.S.S.R.	5 450	280
France	5 072	260
Japan	4 440	228
South Africa	4 356	223
United Kingdom	4 157	213
Brazil	1 316	68
Mexico	1 177	60
Egypt	474	24
China	359	18
India	165	8
Nigeria	61	3
World Average	1 948	100

Source: Electrical Energy Branch, Energy, Mines and Resources Canada.

Table 2.4. International comparison of total electricity consumption growth rates

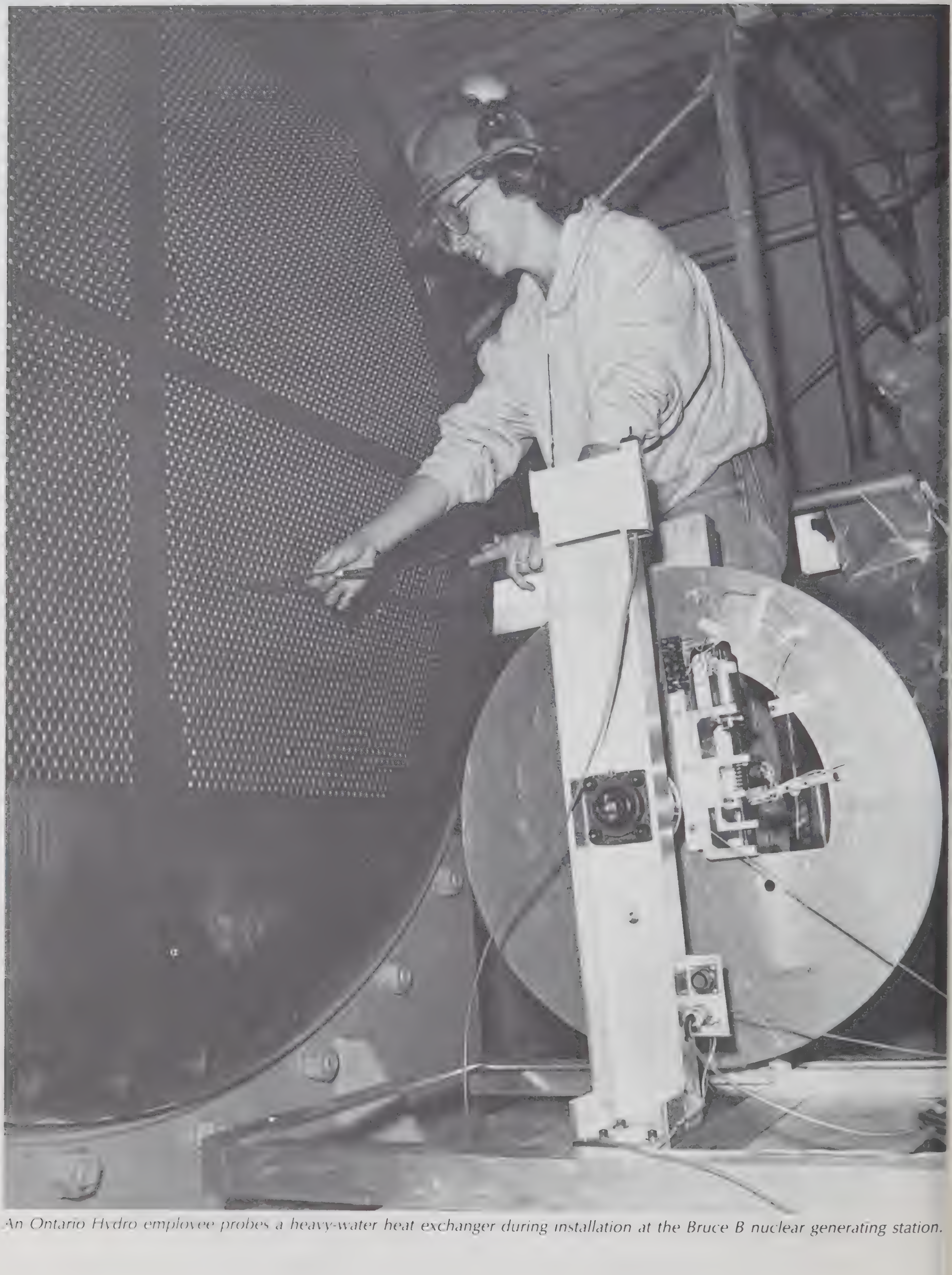
Country	1983	1984	1985	Average 1983-85
		(per cent)		
Iran	14.5	12.6	11.7	13.0
Brazil	7.8	10.9	13.5	10.7
Turkey	5.1	12.5	11.8	9.8
Sweden	11.0	8.3	9.0	9.1
China	7.2	7.6	8.0	7.6
Finland	7.4	7.8	7.0	7.4
India	7.4	9.8	2.8	6.7
Canada	4.3	7.1	5.3	5.6
Norway	6.7	5.0	4.8	5.5
Argentina	7.9	4.5	3.5	5.3
South Africa	2.7	7.7	4.3	4.9
France	2.4	5.2	7.2	4.9
Japan	6.0	5.0	3.4	4.8
Mexico	2.1	5.8	6.1	4.7
Poland	5.9	6.1	2.2	4.7
Belgium	4.2	4.8	3.7	4.2
U.S.S.R.	3.6	5.2	3.6	4.1
Switzerland	2.6	4.7	3.6	3.6
United States	3.1	5.9	1.4	3.5
Spain	2.0	4.7	3.5	3.4
West Germany	2.2	4.6	3.4	3.4
East Germany	2.1	3.5	3.5	3.0
Nigeria	2.9	0.1	5.6	2.9
Italy	0.1	5.7	2.9	2.9
United Kingdom	1.5	1.8	2.8	2.0
World Total	4.1	5.1	3.0	4.1

Source: Energy, Mines and Resources Canada.

Table 2.5. International comparison of electricity consumption per unit of GDP

Country	1975	1980	1985
		(kW.h/US$ 1980)	
Canada	1.23	1.29	1.36
United States	0.76	0.78	0.76
Greece	0.50	0.58	0.56
Ireland	0.50	0.57	0.55
Italy	0.46	0.48	0.48
United Kingdom	0.55	0.53	0.47
Japan	0.57	0.55	0.47
Belgium	0.40	0.43	0.45
France	0.33	0.40	0.44
West Germany	0.45	0.46	0.40
Netherlands	0.36	0.38	0.39
Denmark	0.33	0.39	0.37

Source: Electrical Energy Branch,
Energy, Mines and Resources Canada.



An Ontario Hydro employee probes a heavy-water heat exchanger during installation at the Bruce B nuclear generating station.

The Regulatory Environment

FEDERAL REGULATION

Constitutional Authority

Under the Canadian Constitution, legislative authority for electricity generation, transmission, and distribution rests primarily with the provinces. Federal authority regarding electricity is restricted to nuclear energy and international and interprovincial trade. Federal responsibility for electricity trade stems from Section 91.2 of the Constitution Act, which gives the federal government broad authority over trade and commerce. Federal control of nuclear energy derives from Section 91 of the Act, which permits federal regulation of matters that extend beyond the concern of a single province.

Provincial ownership of most energy resources stems from Section 109 of the Constitution Act which, in turn, is supplemented by Section 92A of the Act, giving provincial legislatures authority over the development, conservation, and management of sites and facilities in the province for the generation and production of electrical energy. Under Section 92A, which was enacted in 1982, the provinces also have authority to make laws regarding interprovincial sales of electricity, as long as such laws do not conflict with federal rights and responsibilities.

National Energy Board

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the National Energy Board Act. Under the Act, the Board advises the federal government on the development and use of energy resources and regulates specific matters concerning oil, gas, and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

Part III of the NEB Act provides for the federal regulation of international power lines. The Board may authorize, without a public hearing, the construction and operation of international power lines not exceeding 50 kV. When reviewing an application for an international power line, the Board determines whether the line is in the public interest by assessing i) the availability of electricity for export, ii) the existence of markets, iii) economic feasibility, iv) financing considerations and Canadian participation, and v) any other consideration that may be relevant. In making this determination, the Board holds public hearings. Applications accepted by the Board are subject to review by the Governor in Council.

The Governor in Council may by order designate a particular interprovincial power line to be regulated in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the NEB Act provides for the regulation of electric power exports. The Board issues export licences in which it imposes terms and conditions on the licensees. The Act restricts the duration of licences to 25 years. In considering an export application, the Board is required to take into account all factors pertaining to the public interest. In particular, the Board must satisfy itself that i) the quantity of electricity to be exported is surplus to reasonably foreseeable domestic requirements, and ii) the price is just and reasonable.

In interpreting the latter requirement the Board has established three guidelines concerning the export price: i) it must recover its appropriate share of the costs incurred in Canada; ii) it must not be less than the price to Canadians for equivalent service in related areas; and iii) it must not be materially less than the least-cost alternative available to the foreign purchaser at the same location in the country of export.

Before licensing exports, the Board normally conducts a public hearing. However, when the export quantities are small (i.e., not more than 50 MW and 250 GW.h/year), or when emergency conditions exist, the Board may issue "orders," authorizing exports without public hearings.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes while at the same time preventing its use for weapons. In 1946, Parliament passed the Atomic Energy Control Act with these objectives in mind.

The Act gave the federal government control over the development, application, and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-person AECB administers and enforces the Act, and licenses uses of radioactive materials and activities involving nuclear energy. It also regulates the health, safety, security, and environmental aspects of nuclear energy. The AECB reports to Parliament through the Minister of Energy, Mines and Resources.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities, and particle accelerators. Prescribed substances include uranium, thorium, heavy water, and

radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import, and export. Before issuing a licence, the Board ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

Federal Environmental Assessment Review Process

In December 1973 Cabinet established the Federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal projects are assessed early in the planning process. A federal project is one initiated by a federal agency, or one that involves federal funding or federal property. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own projects. They conduct an initial screening to determine whether a given project will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department.

If significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the project sponsor prepare an Environmental Impact Statement. If the Minister of the Environment and the initiating Minister concur, the scope of the Panel may be extended to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the project is provided with an opportunity to appear before the Panel.

Once a Panel has completed its deliberations and evaluated all information on a project, it prepares a report containing its findings and recommendations. A Panel could recommend that a project not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating Minister, who must decide to whom the recommendations are directed, to what extent they should be incorporated into terms and conditions governing the project, and in what manner they are to be made public. In the event of a disagreement between the two Ministers, the question may be submitted to Cabinet.

PROVINCIAL REGULATION

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission, and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. All provinces require the environmental effects of proposed projects to be studied.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC. Since 1977, the Board has also had authority under the Electric Power Control Act to review NLH's utility rates, excluding sales to subsidiaries and industrial customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province.

Nova Scotia

Prior to 1976, the Nova Scotia government directly set rates and policies for electric utilities in the province. Since that time, the Board of Commissioners of Public Utilities has taken over this duty and, in accordance with the provincial Public Utilities Act, has full decision-making power.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

Quebec

In Quebec, electricity rates are set by Hydro-Québec and are subject to the approval of the provincial Cabinet. Hydro-Québec's operations are administered by a seventeen-member Board of Directors. The province's 23 industrial, municipal, and independent electricity producers and distributors are regulated by la Régie de l'électricité et du gaz, a provincial body attached to the Department of Energy and Resources.

Ontario

Ontario Hydro is a provincially owned corporation which reports to the provincial government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, the Board of Ontario Hydro is authorized to set the utility's rates and may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board.

Manitoba

Under the Manitoba Hydro Act, rates are set by Manitoba Hydro and reviewed by the Public Utilities Board. The Board provides advice to the provincial government, leaving the Lieutenant Governor in Council with final authority over pricing and other matters related to the supply of electricity.

Electricity exports from Manitoba are the responsibility of the Manitoba Energy Authority. The Board of Directors of the Authority, appointed by the provincial government, has broad statutory authority over all electricity exports from the province. The Energy Authority itself is responsible for initiating export negotiations, signing letters of intent, and concluding agreements. It is thus the export marketing agency for electricity generated by Manitoba Hydro, and as such it is empowered to negotiate terms and conditions for hydroelectric exports.

Saskatchewan

Saskatchewan Power Corporation (SPC) is governed by a Board of Directors that is responsible for the management and operation of the Crown utility. Board members are appointed by the provincial government and report to the province's Crown Management Board. Rates charged to SPC's electricity customers are subject to review and approval by the Public Utilities Review Commission of Saskatchewan.

Alberta

TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power are regulated by the Energy Resources Conservation Board with respect to the development of generation and transmission facilities and changes in service areas. Environmental and social impact assessments and plans to minimize any environmental impacts must be presented to the Board along with applications for construction. The Board's recommendations on generating plants are subject to final approval through Order-in-Council by the Alberta government.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA. The EEMA pools the utilities' costs and resells the power at average prices back to the utilities.

British Columbia

The British Columbia Utilities Commission (BCUC) has general supervisory powers over BC Hydro. Jurisdiction extends to system expansion, operation, financial transactions, and rate schedules. Cominco Limited, which operates generating plants and transmission facilities for industrial purposes, is exempt from regulation by the BCUC. Under a management contract, West Kootenay Power & Light Co. operates and maintains Cominco's facilities. West Kootenay's operations for its direct customers are subject to regulation by the BCUC. New electricity exports require removal permits granted by the BCUC, after authorization by the Lieutenant Governor in Council.

Yukon and Northwest Territories

The Northern Canada Power Commission (NCPC), which is the principal producer of electricity in the North, is a federal Crown corporation, operating under the authority of the Northern Canada Power Commission Act. Under the Act, the NCPC is to be self-sustaining within the rate zones of the Yukon and Northwest Territories. To ensure this, rates charged by utilities must provide sufficient revenue to cover principal and interest charges on federal loans to the Commission and operating costs of the Commission. The NCPC reports to Parliament through the Minister of Indian and Northern Affairs.

Work on Saskatchewan Power's rural underground program continued in 1986. Underground lines are replacing the 14.4 kV overhead lines, which were part of SaskPower's rural electrification program in the late 1940s and early 1950s.

During 1986, 421 855 GW.h of electricity was consumed in Canada. This represented an increase of 3.9 per cent for the year, down from 5.3 per cent in 1985. (The historic average annual increase, during the 1947-86 period, was 6 per cent.) The relatively small consumption growth rate in 1986 was largely a result of slow growth in the economy. Real growth of the Gross Domestic Product (GDP), to which electricity consumption is highly correlated, increased only 3.1 per cent, compared with 4.3 per cent in 1985.

Other factors contributing to the smaller growth in electricity consumption include a relatively mild winter and an end to the trend of conversion from oil to electric space-heating. The off-oil move began in 1980 with a federal program under which eligible consumers received taxable grants to offset conversion costs. Since the termination of the program in March, 1985, the growth of electricity's share of the residential space-heating market has been reduced, although expansion of electricity's share is expected to continue. Twenty-eight per cent of Canadian households are now heated with electricity.

Because of the faster growth rate in electricity consumption than in the GDP, the relative importance of electricity in the Canadian economy continued to increase in 1986. The quantity of electricity consumed, expressed in kilowatt hours per dollar of real GDP (1971$), was 3.14 in 1986, up from 3.12 in 1985, 2.89 in 1980, 2.65 in 1975, and 2.58 in 1970. This represents an increase of about 22 per cent during the period 1970-86.

Table 4.1 shows the growth rates in electricity consumption by province during the period 1982-86. In 1986, growth rates varied considerably, ranging from 13.8 per cent for the Yukon and Northwest Territories, to a negative 0.9 per cent for Saskatchewan. With the exceptions of Prince Edward Island, New Brunswick, Ontario, and the territories, electricity consumption growth rates were smaller than those in 1985.

Electricity consumption by province is given in Table 4.2. The table also indicates generation and trade flows. Quebec was the largest producing and consuming province in 1986, and also the largest in terms of international exports. Total electricity generation, consumption, and net transfers are given in Figure 4.1.

Electricity consumption by sector for the period 1982-86 is reported in Table 4.3. The industrial sector consumed the largest share in 1986, accounting for 51 per cent of the total, followed by the residential sector with 25 per cent, the commercial sector with 22 per cent, and the agricultural sector with the remaining 2 per cent.

Table 4.4 presents electricity consumption growth rates by sector for the period 1982-86. The average growth rate during the past five years was 4.2 per cent for the industrial and farm sectors, and 4.1 per cent for the residential and commercial sectors.

Per Capita Electricity Consumption

Table 4.5 reports per capita electricity consumption by province in 1986. Quebec was the largest electricity user in Canada with 22 911 kW.h per person, while Prince Edward Island was the smallest with 4 856 kW.h per person. Quebec's per capita consumption was 38 per cent above the national average, while

Table 4.1. Provincial growth in electricity consumption, 1982-1986

	1982	1983	1984	1985	1986
			(per cent)		
Newfoundland	- 1.2	4.3	5.7	3.1	1.7
Prince Edward Island	1.9	3.7	2.0	6.5	7.8
Nova Scotia	- 1.5	2.0	7.0	5.8	3.8
New Brunswick	- 3.4	8.4	12.3	1.0	11.6
Quebec	- 2.2	3.6	10.6	6.9	5.1
Ontario	- 1.2	5.2	5.5	3.4	3.7
Manitoba	6.7	3.6	2.9	4.2	2.4
Saskatchewan	2.0	5.4	10.1	2.0	- 0.9
Alberta	12.7	6.9	6.9	7.0	4.1
British Columbia	1.6	1.2	1.9	7.4	0.9
Yukon/N.W.T.	-11.1	-17.4	9.5	2.5	13.8
Canada	0.1	4.2	7.1	5.3	3.9

Source: Energy, Mines and Resources Canada.

Table 4.2. Provincial electricity consumption and generation, 1986

Province	Generation	Exports to Provinces	Exports to U.S.*	Imports from Provinces	Imports from U.S.*	Consumption
			(GW.h)			
Nfld.	40 407	30 695	0	0	0	9 712
P.E.I.	12	0	0	610	0	622
N.S.	7 411	71	0	620	0	7 960
N.B.	12 192	1 230	7 008	7 275	424	11 653
Que.	148 260	14 496	12 674	30 712	35	151 837
Ont.	125 225	22	7 957	8 027	1 693	126 966
Man.	24 052	1 946	6 989	1 081	12	16 210
Sask.	11 913	1 076	151	1 211	64	11 961
Alta.	34 716	617	0	553	3	34 655
B.C.	50 772	553	4 156	617	2 727	49 407
Yuk./N.W.T.	872	0	0	0	0	872
Canada	455 832	50 706	38 935	50 706	4 958	421 855

** Service exchanges are included.*

Source: Electrical Energy Branch,
Energy, Mines and Resources Canada.

Table 4.3. Total electricity consumption in Canada by sector, 1982-1986

	1982	1983	1984	1985	1986
			(TW.h)		
Residential	87.5	90.4	97.3	102.4	106.3
Farm	8.0	8.3	8.9	9.4	9.8
Commercial	75.4	78.6	84.3	88.7	92.2
Industrial	174.0	182.5	195.0	205.5	213.6
Total	345.1	359.8	385.5	406.1	421.9

Source: Energy Information Handbook,
Energy, Mines and Resources Canada, April 1987.

Table 4.4. Electricity consumption growth rates by sector, 1982-1986

	1982	1983	1984	1985	1986
			(per cent)		
Residential	0.7	3.3	7.6	5.2	3.8
Farm	0.0	3.8	7.2	5.6	4.3
Commercial	0.0	4.2	7.3	5.2	3.9
Industrial	-0.2	4.9	6.9	5.4	3.9
Total	0.1	4.2	7.1	5.3	3.9

Source: Energy Information Handbook,
Energy, Mines and Resources Canada, April 1987.

Figure 4.1. Electricity generation, consumption and net transfers, 1986 (GW.h)

G: GENERATION
C: CONSUMPTION
E: NET EXPORTS
I: NET IMPORTS

Prince Edward Island's was 70 per cent below the national average. Quebec, British Columbia, and Newfoundland were the only provinces in which per capita consumption levels in 1986 were higher than the national average.

Electricity and Primary and Secondary Energy

Electricity constitutes a significant share of primary and secondary energy demand in Canada. Primary energy refers to the amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. Conversion losses refer to losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels (coal, oil or natural gas) into electricity in thermal power generation. Domestic demand for primary energy by fuel type in 1986 is summarized in Figure 4.2.

Secondary energy is the amount of energy available to, and used by, the consumer in its final form. Electricity constitutes a much smaller share of secondary energy demand than primary energy demand. Figure 4.3 illustrates the percentage shares of Canadian secondary energy demand by fuel type in 1986: electricity's share was 23 per cent, petroleum's was 41 per cent, and natural gas's was 26 per cent.

Peak Demand

Peak demand grew by 1.8 per cent in 1986, up from 72 145 MW in 1985 to 73 470 MW in 1986. This increase is much less than the 4.8 per cent registered in 1985, and substantially less than the 5.7 per cent for the historic period 1960-1986.

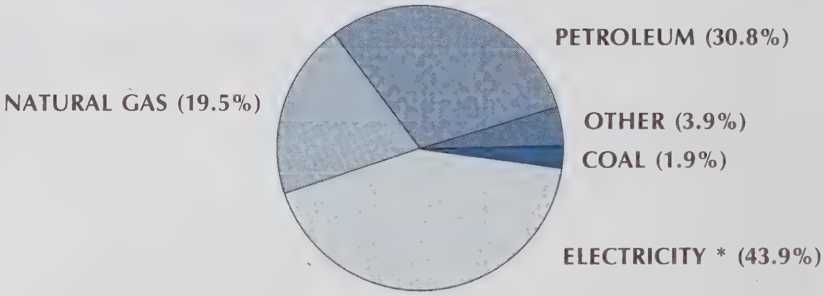
Because of the strong growth of New Brunswick's economy, peak demand in the province grew

Table 4.5. Per capita electricity consumption by province, 1986

Province	Per Capita Consumption (kW.h/person)	Canada Per Capita = 100
Quebec	22 911	138
British Columbia	17 003	103
Newfoundland	16 739	102
New Brunswick	16 160	98
Manitoba	15 034	91
Alberta	14 504	88
Ontario	13 828	84
Yukon and N.W.T.	11 816	72
Saskatchewan	11 714	71
Nova Scotia	8 996	55
Prince Edward Island	4 856	30
Canada	16 485	100

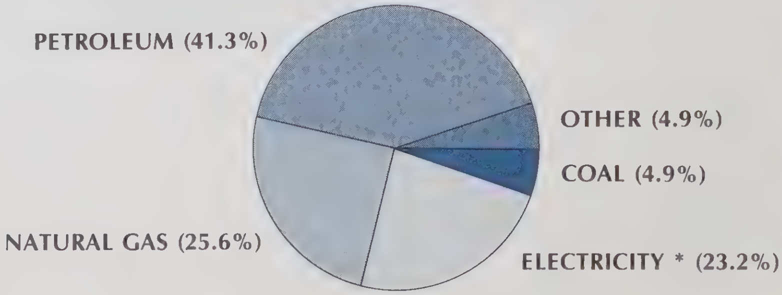
Source: Energy, Mines and Resources Canada.

Figure 4.2. Primary energy consumption in Canada, 1986



TOTAL CONSUMPTION: 9956 PETAJOULES
*** converted at 10.5 megajoules per kilowatt hour**

Figure 4.3. Secondary energy consumption in Canada, 1986



TOTAL CONSUMPTION: 6087 PETAJOULES
*** converted at 3.5 megajoules per kilowatt hour**

Table 4.6. Peak demand in Canada*

	1985	1986	Average Annual Growth Rates 1985-1986	1960-1986
	(MW)		(per cent)	
Newfoundland	1 573	1 655	5.2	7.4
Prince Edward Island	107	112	4.7	6.7
Nova Scotia	1 380	1 504	9.0	5.7
New Brunswick	1 957	2 260	15.5	7.5
Quebec	26 284	26 443	0.6	5.5
Ontario	21 533	21 911	1.8	4.8
Manitoba	2 985	3 004	0.6	5.6
Saskatchewan	2 197	2 179	- 0.8	5.8
Alberta	5 388	5 319	- 1.3	8.0
British Columbia	8 592	8 921	3.8	5.7
Yukon/N.W.T.	149	162	8.7	6.2
Canada	72 145	73 470	1.8	5.7

** Includes firm peak and non-firm peak.*

Source: Energy, Mines and Resources Canada.

15.5 per cent in 1986. Alberta and Saskatchewan were the only two provinces where peak demand declined. Table 4.6 reports peak demand by province for 1985 and 1986, and peak demand growth rates for 1986 and the historic period 1960-1986.

Load Factor

Load factor is defined as the ratio of average demand to peak demand, both measured in megawatts. (Average demand equals annual energy consumption divided by 8 760 hours per year.) In 1986 the load factor for Canada as a whole was 65.6 per cent, up from 64.3 per cent in 1985. Load factors for Newfoundland, Nova Scotia, New Brunswick, and British Columbia declined in 1986, indicating that in these provinces the growth of peak demand was greater than that of electricity consumption.

Table 4.7. Load factor in Canada

	1985	1986
	(per cent)	
Newfoundland	69.3	67.0
Prince Edward Island	61.6	63.4
Nova Scotia	63.4	60.3
New Brunswick	60.9	58.9
Quebec	62.8	65.5
Ontario	64.9	66.2
Manitoba	60.6	61.6
Saskatchewan	62.7	62.7
Alberta	70.5	74.4
British Columbia	65.1	63.2
Yukon/N.W.T.	58.7	61.5
Canada	64.3	65.6

Source: Energy, Mines and Resources Canada.

Electricity Generation

Electricity generation increased 2.1 per cent in 1986 to 455 832 GW.h. Of this total, 421 855 GW.h was for use in Canada and the remainder was exported. The sources of generation are given in Table 5.1. The major generating stations in each province are shown in Figure 5.1.

Hydro generation increased 2.3 per cent in 1986, and continued to account for 67 per cent of total generation. Electricity generation from fossil fuels declined by 8.6 per cent in 1986, compared with a decrease of 3.9 per cent in 1985. The fossil fuel share of total electricity generation was 18 per cent, a reduction of 2 per cent from the previous year. The generation of electricity from coal decreased by 8 per cent, from 79 460 GW.h in 1985 to 73 116 GW.h in 1986. In Ontario, coal-fired generation decreased by 6 000 GW.h, largely because of the addition of new nuclear capacity.

Although world oil prices declined significantly in 1986, generation from oil-fired stations decreased by 29 per cent, from 7 166 GW.h in 1985 to 5 110 GW.h in 1986. Generation from natural gas increased by 40 per cent, from 1 955 GW.h in 1985 to 2 731 GW.h in 1986. Total nuclear generation increased by 17.8 per cent, from 57 095 GW.h in 1985 to 67 232 GW.h in 1986.

Table 5.2 shows energy generation by province for 1985 and 1986, and generation growth rates for 1986 over 1985 and the period 1960-86. Quebec was the largest electricity producer in 1986, with 33 per cent of the total; Ontario was second with 28 per cent; and British Columbia was third with 11 per cent. British Columbia's generation declined by 14 per cent in 1986, primarily because of a substantial reduction in exports to the United States. Newfoundland's slight reduction was due to lower production at the Churchill Falls station in Labrador.

Prince Edward Island was the only province in Canada with a negative growth rate for electricity generation during the period 1960-86. The province's electrical generating plants are relatively small, are fuelled by oil, and are consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase economy energy from New Brunswick. In addition, in 1981 P.E.I. purchased a 10-per cent ownership interest in the 200-MW, coal/oil-fired plant at Dalhousie, N.B., to stabilize the island's electricity costs. Because of the interconnection and joint ownership, P.E.I. has reduced the amount of generation from its oil-fired stations.

Table 5.3 presents energy generation by fuel type for the provinces and territories. Production by region and energy source is shown in Figure 5.2. In Newfoundland, Quebec, Manitoba, and British Columbia, hydro generation accounted for more than 96 per cent of the total in 1986. In Alberta, about 92 per cent of total generation came from coal-fired stations. Coal generation was also quite important in Nova Scotia and Saskatchewan, at 78 per cent and 68 per cent, respectively.

Ontario, Quebec, and New Brunswick are the only three provinces with nuclear energy in Canada. In 1986, nuclear generation accounted for 47 per cent of Ontario's total electricity generation, 43 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity generation from natural gas occurs mainly among industries that generate power for their own use. In all provinces but Newfoundland, Nova Scotia, and New Brunswick, oil is used mainly for peaking purposes.

Fuel Use in 1986

Electricity generated from conventional thermal and nuclear sources totalled about 148 189 GW.h in 1986, or about 33 per cent of total generation. In terms of heat content, fuels used for this generation amounted to the equivalent of 267 million barrels of oil. A breakdown of the fuels used by utilities is provided in Table 5.4. Ontario was the largest user, accounting for approximately

Table 5.1. Sources of electricity production

Fuel Type	1985	1986	Average Annual Growth Rates 1985-1986	1960-1986
	(GW.h)		(per cent)	
Hydro	300 737 (67%)	307 643 (67%)	2.3	4.2
Thermal	88 581 (20%)	80 957 (18%)	- 8.6	9.2
Nuclear	57 095 (13%)	67 232 (15%)	17.8	35.2*
Total	446 413 (100%)	455 832 (100%)	2.1	5.5

** Nuclear generation is calculated for the period 1965-86.*

Source: Statistics Canada.

Figure 5.1. Major generating stations by province, 1986. (MW)

53 per cent of the total. Alberta was second, accounting for 23 per cent, and Saskatchewan ranked third with a 9 per cent share.

New Brunswick remained the largest user of oil due in part to a unit participation contract with Maine Electric Power Company (MEPCo), under which NB Power exports firm energy from its Coleson Cove oil-fired station.

Alberta is the largest user of coal for electricity generation, accounting for 47 per cent of the coal used in Canada for electricity generation.

Energy sources of electricity generation changed significantly in 1986 from the previous year. The decline in coal use, from 39 million tonnes in 1985 to about 38 million tonnes in 1986, is attributed mainly to a 27 per cent decline in export sales from Ontario. In 1986, about 89 per cent of Ontario's electricity exports came from coal-fired stations, compared with 96 per cent in 1985. Oil use also declined, dropping from 10.2 million barrels in 1985 to 9.4

Table 5.2. Electricity generation by province

	1985	1986	Average Annual Growth Rates 1985-1986	1960-1986
	(GW.h)		(per cent)	
Newfoundland	41 387	40 407	-2.4	13.6
Prince Edward Island	2	12	500.0	-7.0
Nova Scotia	7 511	7 411	-1.3	5.6
New Brunswick	11 422	12 192	6.7	7.8
Quebec	136 727	148 260	8.4	4.3
Ontario	121 661	125 225	2.9	5.0
Manitoba	22 742	24 052	5.8	7.3
Saskatchewan	11 816	11 913	0.8	6.6
Alberta	33 253	34 716	4.4	9.3
British Columbia	59 126	50 772	-14.1	5.3
Yukon/N.W.T.	766	872	13.8	6.6
Canada	446 413	455 832	2.1	5.5

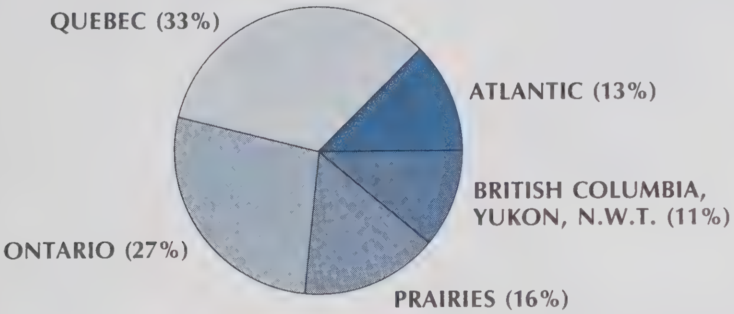
Source: Energy, Mines and Resources Canada.

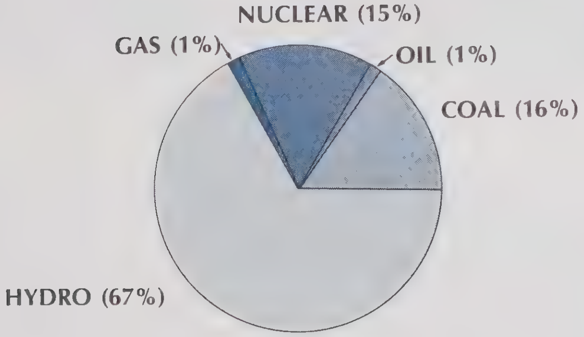
Table 5.3. Electrical energy production by fuel type, 1986

	Coal	Oil	Natural Gas	Nuclear	Hydro	Total
			(GW.h)			
Newfoundland	0	1 278	0	0	39 129	40 407
Prince Edward Island	0	12	0	0	0	12
Nova Scotia	5 748	662	0	0	1 001	7 411
New Brunswick	1 365	2 454	0	5 227	3 146	12 192
Quebec	0	140	0	3 792	144 328	148 260
Ontario	25 950	12	0	58 213	41 050	125 225
Manitoba	163	37	12	0	23 840	24 052
Saskatchewan	8 106	7	36	0	3 764	11 913
Alberta	31 784	18	1 114	0	1 800	34 716
British Columbia	0	280	1 569	0	48 923	50 772
Yukon	0	22	0	0	315	337
Northwest Territories	0	188	0	0	347	535
Canada	73 116	5 110	2 731	67 232	307 643	455 832

Source: Energy, Mines and Resources Canada.

Figure 5.2. Production by region and energy source, 1986





Total: 455 832 GW.h

million barrels in 1986. Almost all of this reduction occurred in Newfoundland, where hydro generation was used to replace base-load oil generation. Uranium use increased due to the additions of Ontario's Bruce 7 and Pickering 8 nuclear reactors. Natural gas use also increased considerably, with most of the increase occurring in British Columbia.

Provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil in gas turbines or diesel plants. In the Yukon and Northwest Territories, Canadian diesel oil was used to supply electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

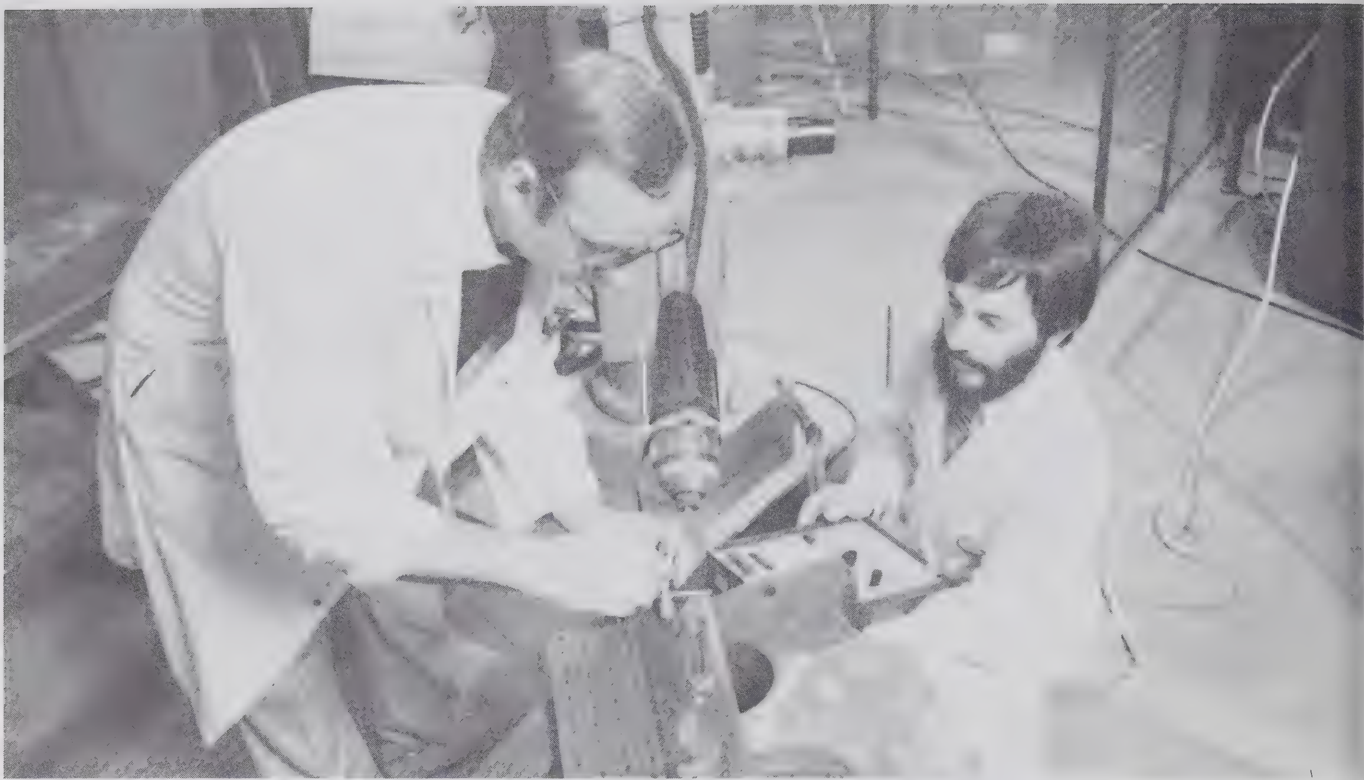
In 1986, about 68 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia, and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

Table 5.4. Fossil fuels used by utilities, 1986

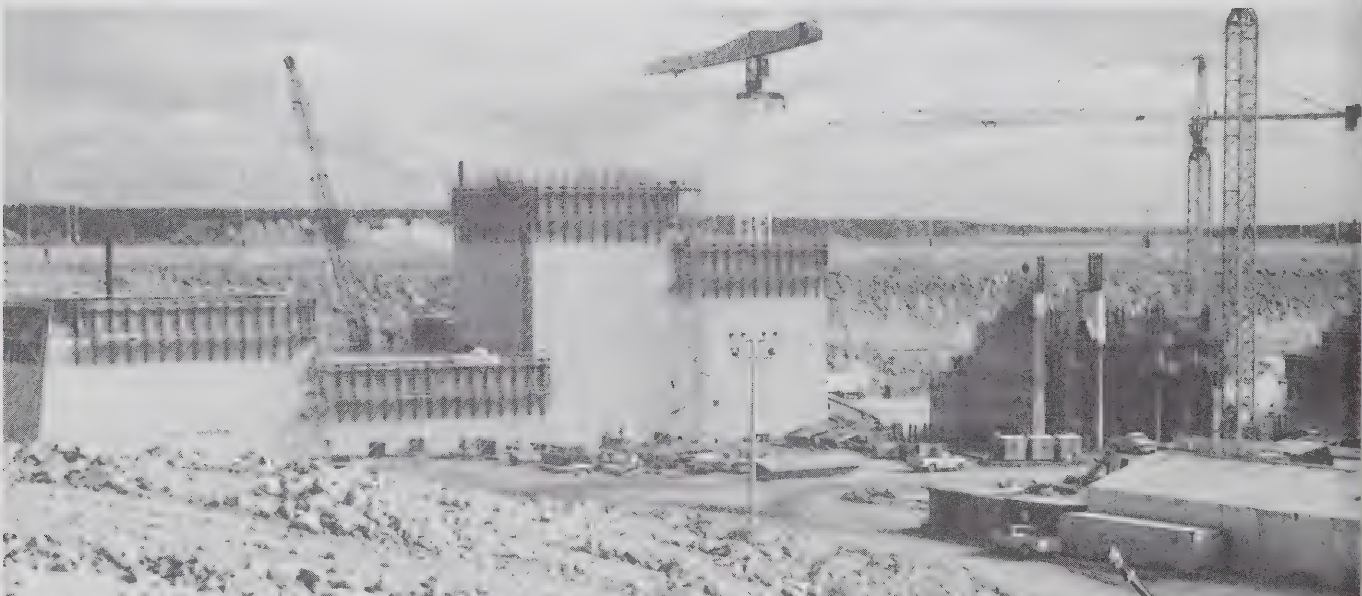
Province	Coal (10^3 tonnes)	Oil (m^3)	Gas ($10^6 m^3$)	Uranium ($10^3 g$)
Newfoundland	0	335 245	-	-
Prince Edward Island	0	8 900	-	-
Nova Scotia	2 143	207 065	-	-
New Brunswick	528	602 721	-	103 000
Quebec	-	71 323	-	73 000
Ontario	10 276	20 446	-	1 110 000
Manitoba	120	4 292	15	-
Saskatchewan	6 775	17 144	46	-
Alberta	17 719	35 454	681	-
British Columbia	-	110 020	889	-
Northwest Territories/Yukon	-	79 572	-	-
Canada	37 561	1 492 182	1 631	1 276 000

Source: Energy, Mines and Resources Canada.

Note: 1 m^3 oil = 6.3 bbls
1 m^3 gas = 35.5 ft^3
1 tonne = 1000 kg



A welding robot assists employees at the Hydro-Québec Institute of Research.



Construction of Manitoba Hydro's Limestone generating station continued in 1986. Shown from the upstream side, the structure's service bay reached a height of 86 metres above sea level, the first section of the project to reach its finished height. By the end of the construction season, more than 170 000 cubic metres of concrete had been poured at the site.

Capacity and Reserve Margins

Capacity Additions

In 1986, total Canadian generating capacity increased by 2 696 MW to 98 368 MW at year end, a 1.7 per cent increase over 1985. Nuclear capacity additions totalled 1 346 MW, hydro 970 MW, and coal 380 MW, representing 50 per cent, 36 per cent, and 14 per cent of the total additions respectively. A summary of the major additions is presented in Table 6.1. Installed capacity by fuel type for Canada as a whole during the period 1920-86 is reported in Table A1 of the Appendix.

Total installed capacity by principal fuel type and province for 1986 is given in Table 6.2. Installed capacity by region and energy source for Canada is shown in Figure 6.1. Figure 6.2 illustrates historical installed capacity by fuel type for Canada during the period 1960-86.

Table 6.2 indicates that in 1986 Ontario's installed capacity was the largest in Canada, with 31 per cent of the total. Quebec was second with 28 per cent and British Columbia was third with 13 per cent.

Although the market share of hydro has decreased since 1960, it is still the most important source of electric power in Canada. In 1986, hydro accounted for 58 per cent of total installed generating capacity, followed by coal with 18 per cent, nuclear with 11 per cent, oil with 8 per cent, and natural gas with 5 per cent.

Table 6.3 presents total installed capacity by province for 1985 and 1986, along with a comparison of the annual growth rate for 1985-86 to the annual growth rate for the period 1960-86. In 1986, only Quebec, Ontario, and Alberta had net additions to their electrical systems. Installed capacity for British Columbia, Saskatchewan, and the territories was slightly reduced because of plant retirements. In the four Atlantic provinces and Manitoba, capacity did not change in 1986. The generating capacity growth rate increased only 1.7 per cent for Canada in 1986, compared with

Table 6.1. Major additions to installed generating capacity, 1986

	Project	Plant Type	No. of Units	Capacity (MW)
Quebec	LG-4	Hydro	2	885
Ontario	Bruce 7	Nuclear	1	830
	Pickering 8	Nuclear	1	516
Saskatchewan	Nipawin	Hydro	1	85
Alberta	Sheerness	Steam (coal)	1	380

Source: Energy, Mines and Resources Canada.

Table 6.2. Installed generating capacity by fuel type, 1986

	Hydro	Coal	Nuclear	Oil	Natural Gas	Total
			(MW)			
Newfoundland	6 417	0	0	757	0	7 174
Prince Edward Island	0	0	0	122	0	122
Nova Scotia	366	954	0	1 035	0	2 355
New Brunswick	903	307	635	1 589	0	3 434
Quebec	25 812	0	638	1 111	0	27 561
Ontario	7 172	9 235	9 711	2 736	1 552	30 406
Manitoba	3 641	442	0	55	4	4 142
Saskatchewan	829	1 680	0	7	304	2 820
Alberta	734	4 966	0	79	1 819	7 598
British Columbia	10 844	0	0	300	1 299	12 443
Yukon	82	0	0	41	0	123
Northwest Territories	49	0	0	141	0	190
Canada	56 849	17 584	10 984	7 973	4 978	98 368

Source: Statistics Canada Publication 57-204.
Energy, Mines and Resources Canada.

the historical average of 5.7 per cent registered during the period 1960-86.

Surplus Capacity

There have been two distinct periods in the growth of electricity demand in Canada since World War II. From 1947 to 1974, there was a period of rapid growth, with an average annual increase of 6.8 per cent. Following the oil crisis of 1973-74, electricity growth slowed to an average rate of 3.9 per cent for the period 1975-86. Electricity consumption actually declined in 1975 and did not grow in 1982.

This shift, from a long period of sustained rapid growth to one of slower growth, resulted in excess generating capacity. In the early 1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand but also to displace fossil-fuelled electricity production. As the growth in demand slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to domestic requirements.

In calculating surplus capacity, the generating capability, rather than generating capacity, is normally used. Generating capability measures the expected power of all available generating facilities of the province (or country) at the time of one hour firm peak load. This may differ from the generating capacity measured by the nameplate rating of the equipment (see Table 6.2).

The variations between generating capability and generating capacity may be caused by a number of factors. These include high water levels in reservoirs, resulting in a higher waterhead and greater generation than the nameplate capacity; the impossibility of placing all pieces of equipment on the line at the same time; and low

Figure 6.1. Capacity by region and energy source, 1986

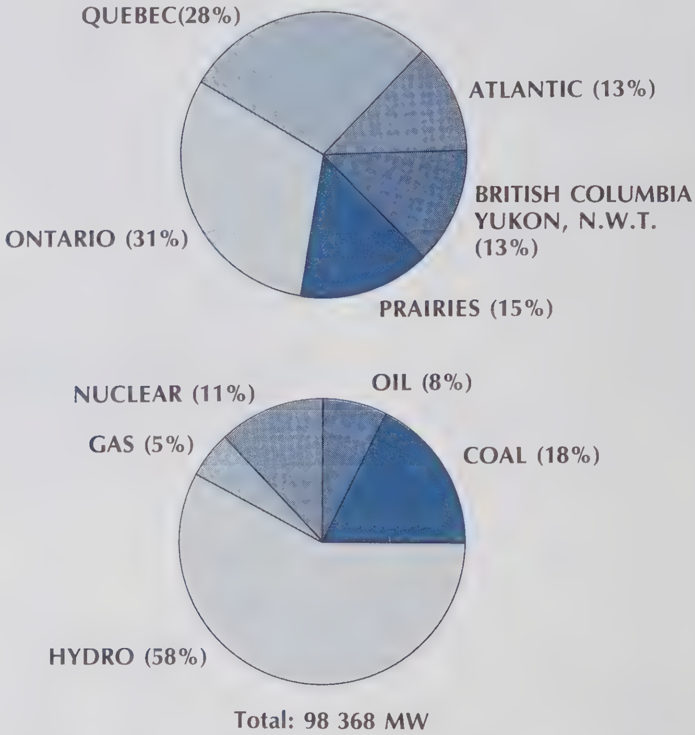
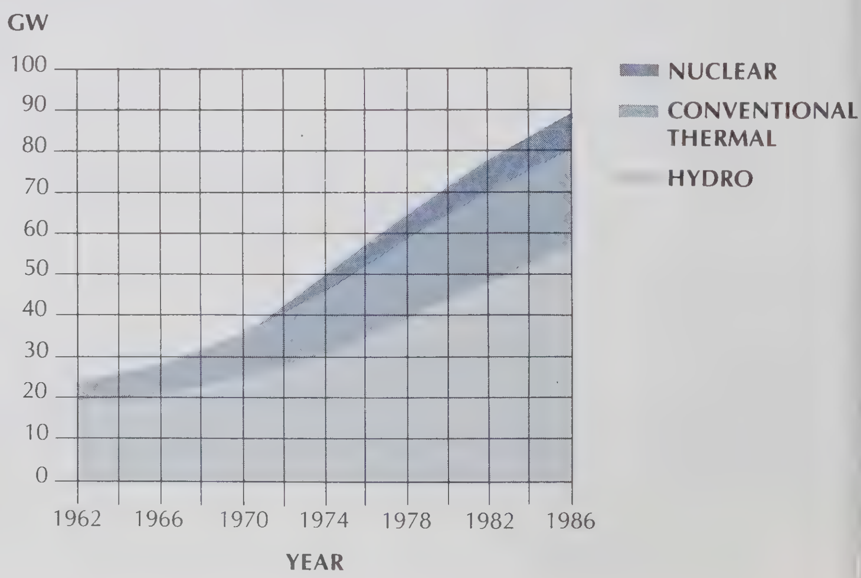


Figure 6.2. Historical installed capacity by fuel type, 1960-1986



water, ice, or unreliable equipment, which may result in capability below capacity.

Present Reserve Margin

The reserve margin of an electrical system is defined as the excess of generating capability for in-province use over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Column 3 of Table 6.4 presents the reserve margin in the 10 provinces in 1986. The largest reserve was in British Columbia with 46 per cent, followed by Manitoba with 40 per cent, Nova Scotia with 38 per cent, Prince Edward Island with 35 per cent, and New Brunswick with 34 per cent. The reserve margin for Canada as a whole was 27 per cent.

Capacity Reserve Requirements

Normal practice in an electrical system is that a certain amount of capacity (expressed as a percentage of firm peak load) is designated to allow for scheduled maintenance, planned outages, and unexpected peak demand. This proportion is usually called the capacity reserve requirement. It varies from utility to utility, depending on the capacity mix of the particular system. Column 4 of Table 6.4 reports the capacity reserve requirement in each province for 1986. Ontario Hydro had the largest capacity reserve with 23 per cent, followed by the Alberta integrated system

Table 6.3. Installed capacity by province

	1985	1986	Average Annual Growth Rates 1985-1986	1960-1986
	(MW)		(per cent)	
Newfoundland	7 174	7 174	0.0	12.8
Prince Edward Island	122	122	0.0	4.7
Nova Scotia	2 355	2 355	0.0	6.1
New Brunswick	3 434	3 434	0.0	8.7
Quebec	27 215	27 561	1.3	4.4
Ontario	29 395	30 406	3.4	5.7
Manitoba	4 142	4 142	0.0	5.5
Saskatchewan	2 826	2 820	-0.2	5.1
Alberta	7 220	7 598	5.2	8.5
British Columbia	12 504	12 443	-0.5	5.7
Yukon/N.W.T.	315	313	-0.6	6.4
Canada	96 702	98 368	1.7	5.7

Source: Energy, Mines and Resources Canada.

Table 6.4. Surplus capacity, 1986

	Generating Capability for In-Province Use (1)	In-Province Firm Peak (2)	Reserve Margin (3) = (1-2)/(2)	Capacity Reserve Requirement (4)*	Net Surplus Capacity (5) = (3-4)
	(MW)			(per cent)	
*Nfld.***	1 779	1 362	31	17	14
P.E.I.	135	100	35	15	20
N.S.	1 871	1 352	38	20	18
N.B.	2 987	2 228	34	20	14
Que.	31 498	26 844	17	10	7
Ont.	25 790	20 996	23	23	0
Man.	4 384	3 130	40	15	25
Sask.	2 803	2 273	23	15	8
Alta.	7 573	5 850	30	22	8
B.C.	12 736	8 717	46	15	31
*Canada****	92 618	73 154	27	17	10

* *Expressed as a percentage of in-province firm peak.*
** *Does not include Labrador.*
*** *Figures include NCPC's capacity.*

Source: Energy, Mines and Resources Canada.

with 22 per cent; Hydro-Québec had the lowest capacity reserve with 10 per cent.

Net Surplus Capacity

Net surplus capacity is defined as the reserve margin less the reserve capacity requirement. Column 5 of Table 6.4 indicates existing net surplus generating capacity by province for 1986. Because of low growth in electricity consumption in 1986, all provinces had net surplus capacity, with the exception of Ontario. British Columbia had the greatest net surplus capacity with 31 per cent, followed by Manitoba with 25 per cent and Prince Edward Island with 20 per cent. For Canada as a whole, net surplus capacity was 10 per cent, or 7 315 MW. Table 6.5 summarizes net surplus capacity by province for the period 1982-86. Because of its high reserve requirement, Ontario has had no net surplus capacity in the past five years.

Table 6.5. Changes in net surplus, 1982-1986

	1982	1983	1984	1985	1986
			(per cent)		
Newfoundland	22	13	15	34	14
Prince Edward Island	16	19	15	25	20
Nova Scotia	15	23	38	18	18
New Brunswick	28	40	38	19	14
Quebec	0	18	19	10	7
Ontario	-1	-11	-11	-12	0
Manitoba	39	35	40	33	25
Saskatchewan	-3	3	-2	0	8
Alberta	14	16	19	14	8
British Columbia	26	21	32	35	31
Canada	8	9	11	9	10

Source: Energy, Mines and Resources Canada.

Lobstick, shown above, is one of the main control structures of the Churchill Falls hydroelectric development in Labrador.

Electricity Trade

International Trade

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line (12 000 volts) was built across the border at Niagara Falls. This early interconnection enabled Canada to market its abundant hydroelectric power in the United States. For most of the century, electricity trade between Canada and the United States was balanced. However, between the early 1970s and 1986, Canada's net exports to the United States grew steadily in both quantity and revenue. Electricity trade statistics for the period 1982-86 are summarized in Table 7.1.

In 1986, electricity exports to the United States (excluding non-cash service exchange) were 35 271 GW.h, a decline of 15 per cent from 1985. Two key conditions contributed to this reduction: the lowering of international oil prices, which has resulted in some U.S. electric utilities increasing their electricity generation from oil-fired station rather importing electricity from Canada; and the Bonneville Power Administration (BPA) intertie access policy, which has limited BC Hydro's ability to deliver electricity to Southern California. Electricity exports in 1986 accounted for 7.7 per cent of Canada's total generation, down from 9.3 per cent in 1985.

Export revenues dropped 24 per cent in 1986 to $1.086 bilion, compared to $1.425 billion in 1985. Electricity imports from the United States in 1986 were 235 GW.h, and import costs to Canada were about $9 million, the same as the previous year.

Approximately 72 per cent of the electricity exported in 1986 was

Table 7.1. Canada-U.S. electricity trade, 1982-1986

	1982	1983	1984	1985	1986
			(GW.h)		
Exports (a)	32 986	36 907	37 572	41 520	35 271
Imports (a)	268	211	291	221	235
Net exports	32 718	36 696	37 281	41 299	35 036
Type of exports: (b)					
Firm	5 829	10 218	10 852	12 305	9 756
Interruptible	27 157	26 689	26 720	29 215	25 515
Total	32 986	36 907	37 572	41 520	35 271
Generation source for exports: (c)					
Hydro (d)	20 114	21 627	22 816	28 915	25 727
Imported coal	10 315	11 704	10 582	8 245	5 389
Imported oil	1 959	1 201	1 552	1 157	846
Domestic coal/oil	502	519	711	956	825
Nuclear	96	1 856	1 911	2 247	2 484
Total	32 986	36 907	37 572	41 520	35 271
			(million $)		
Export revenue	1 106	1 249	1 376	1 425	1 086
Import costs	5	6	10	9	9
Net revenue	1 101	1 243	1 366	1 416	1 077

(a) Excludes non-cash exchanges.

(b) 'Firm exports' refers to energy that must be made available on demand.
'Interruptible exports' refers to energy that can be interrupted upon notice by the supplier, and which therefore requires backup capacity on the part of the buyer.

(c) Estimated from data of major utilities.

(d) Electricity purchased by a utility from another Canadian utility for the purposes of export has been considered hydro-generated. Exports from a number of smaller utilities have also been considered hydro-generated.

Source: Energy, Mines and Resources Canada.

interruptible (i.e. available only when surplus to the selling utility's needs). This represents a marginal percentage increase over 1985. Hydro-generated electricity continued to be the main source of Canada's electricity exports, accounting for more than 73 per cent of the total exported.

Provincial sources of exports, revenues, and average revenues received in 1985 and 1986 are reported in Table 7.2. New Brunswick, Quebec, and Manitoba showed increases in the quantity of electricity exported in 1986, while Ontario, Saskatchewan, and British Columbia showed decreases. The largest decrease occurred in British Columbia where the quantity exported was equal to only 20 per cent of the previous year's level. This decline was the result of a surplus of energy in the Pacific Northwest (compared to a deficit a year earlier) and the Bonneville Power Administration's unwillingness to grant BC Hydro access to its intertie with California.

The average revenue received from electricity exports in 1986 varied significantly from province to province. New Brunswick received the highest average revenue, 41.9 mills per kW.h, while Saskatchewan received the lowest, 10.1 mills per kW.h. These differences reflect significant differences in the product exported, the cost of generation, and the alternatives available in the export market.

As indicated in Table 7.2, average revenues for all exporting provinces fell in 1986. The dramatic decline in the international price of crude oil, from US$29 per barrel in 1985 to about US$17 per barrel in 1986, was the main factor contributing to lower average revenues. As mentioned above, more than 72 per cent of electricity exports to the United States in 1986 were interruptible sales, which are largely priced in relation to the importing utility's marginal cost of oil-fired generation. The declining world price of oil resulted in a reduction in U.S. generation costs which, in turn, reduced Canada's export prices.

Table 7.3 presents the proportion of firm and interruptible electricity exports for the six exporting provinces. While firm exports accounted for just under 28 per cent of total Canadian electricity exports in 1986, the proportion of firm to total exports ranged from 1 per cent in Manitoba to almost 42 per cent in Ontario. The high proportion of firm power exports in Ontario partly accounts for the province experiencing only a slight reduction in its average revenue in 1986, despite lower world oil prices.

Table 7.4 reports the energy sources of electricity exported during 1986. Exports from Quebec and British Columbia were generated entirely from hydroelectric stations. Manitoba's exports also overwhelmingly came from hydro. Exports from Saskatchewan were generated entirely from indigenous coal, while Ontario's exports came primarily from thermal stations using imported coal. Nuclear-generated power for export increased significantly in Ontario, from 2.5 per cent in 1985 to 9.1 per cent in 1986. In New Brunswick, electricity exports were generated from nuclear, oil, and coal sources. The hydro-based electricity exported by New Brunswick was purchased from Quebec and not generated within the province. New Brunswick was the only province using base-load oil-fired generation for exports.

Export markets in the U.S. are summarized in Table 7.5. New York State was the most important market for Canadian electricity exports. Of the total 35 271 GW.h exported in 1986, New York received about 15 466 GW.h, or

Table 7.2. Electricity exports and revenues by province, 1985-1986*

	Quantity (GW.h)			Revenue (million $)			Average revenue (mills/kW.h)		
	1985	1986	% Change	1985	1986	% Change	1985	1986	% Change
N.B.	6 130	6 652	8	332.9	278.8	-16	54.3	41.9	-23
Que.	9 585	12 640	31	332.0	378.3	13	34.6	29.9	-14
Ont.	9 329	6 757	-27	379.2	270.3	-28	40.7	40.0	-2
Man.	5 642	7 009	24	96.1	111.7	16	17.0	15.9	-7
Sask.	128	110	-13	3.2	1.1	-63	25.1	10.1	-60
B.C.	10 706	2 103	-80	281.1	45.5	-83	26.3	21.7	-18
Canada	41 520	35 271	-15	1 424.7	1 086.0	-24	34.3	30.8	-10

** Excludes non-cash exchanges.*

Source: Compiled from National Energy Board Annual Report.

44 per cent. New York accounted for 48 per cent of Canada's total $1.086 billion export revenue.

The New England states were also an important market for Canadian electricity exports in 1986. They imported 9 840 GW.h from New Brunswick, Quebec, and Ontario, accounting for 28 per cent of total Canadian electricity exports. New England contributed $387 million, or 36 per cent of Canada's total export revenue.

Because of the decrease in quantity exported, Canadian electricity exports, as a percentage of total electrical energy demand in the United States, dropped from 1.7 per cent in 1985 to 1.4 per cent in 1986. However, the importance of Canadian exports varied from region to region. Exports to New York accounted for 12 per cent of the state's total electricity consumption in 1986. The corresponding ratio was 9 per cent for New England, 6 per cent for the Midwest, and 1 per cent for California.

Provincial shares of total Canadian electricity exports are shown in Table 7.6. Quebec was the leading exporter in 1986, followed by Manitoba, Ontario, and New Brunswick.

Electricity Trade and the Economy

The export of electricity is an important aspect of Canada's foreign trade. Although total electricity export revenue accounted for only 0.9 per cent of total merchandise exports in 1986, Figure 7.1 shows that net electricity export revenue contributed 14 per cent of the total $7.817 billion merchandise trade balance in the same year.

Canadian energy trade by fuel type during the period 1982-86 is reported in Table 7.7. In 1986, total electricity export revenue accounted for about 9 per cent of total energy export revenue. In

Table 7.3. Firm and interruptible exports, 1986*

	Firm	Interruptible	Interruptible	Firm
	(GW.h)		(per cent)	
New Brunswick	2 422	4 230	63.6	36.4
Quebec	4 125	8 515	67.4	32.6
Ontario	2 813	3 944	58.4	41.6
Manitoba	87	6 922	98.8	1.2
Saskatchewan	12	98	89.4	10.6
British Columbia	297	1 806	85.9	14.1
Canada	9 756	25 515	72.3	27.7

** Exchanges are excluded.*

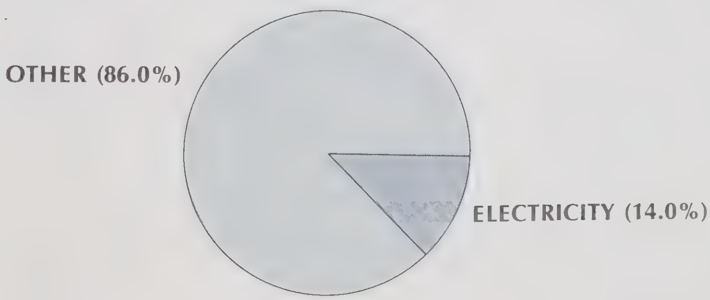
Source: National Energy Board.

Table 7.4. Energy sources of electricity exports, 1986

	Oil	Coal	Nuclear	Hydro	Total
			(per cent)		
New Brunswick	13.4	11.1	26.8	48.7	100
Quebec	-	-	-	100.0	100
Ontario	-	89.4	9.1	1.5	100
Manitoba	-	0.7	-	99.3	100
Saskatchewan	-	100.0	-	-	100
British Columbia	-	-	-	100.0	100
Canada	4.0	16.0	7.0	73.0	100

Source: Energy, Mines and Resources Canada.

Figure 7.1. Net electricity exports and Canadian merchandise trade, 1986



Total Merchandise Trade Balance
$7.817 Billion

terms of net revenue, however, electricity accounted for 16 per cent, as shown in Figure 7.2.

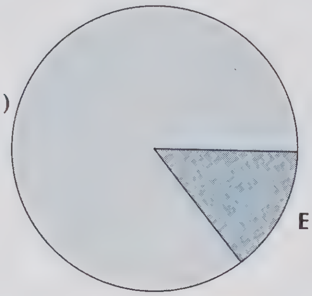
Interprovincial Trade

The most significant change in interprovincial transfers during 1986 was a 24-per cent increase in sales from Quebec to New Brunswick, from 5 827 GW.h in 1985 to 7 204 GW.h in 1986. This change was mainly due to increased electricity demand in New Brunswick and increased electricity exports from New Brunswick to the United States.

Quebec's purchases from Newfoundland declined for the second consecutive year, dropping by 4 per cent, from 31 837 GW.h in 1985 to 30 695 GW.h in 1986. In Ontario, two new nuclear reactors, Pickering 8 and Bruce 7, came into service in 1986. With the additional capacity provided by these new units, sales of electricity from Quebec to Ontario declined by 16 per cent, from 8 664 GW.h in 1985 to 7 292 GW.h in 1986.

Interprovincial transfers during the period 1982-86 are summarized in Table 7.8. More information on exports and imports by province is provided in Figure 7.3 and Table A5 in the Appendix.

Figure 7.2. Net electricity exports and Canadian energy trade, 1986



Total Energy Trade Balance
$6.841 Billion

Table 7.5. Exporting provinces and importing markets, 1986

Exporting Province	Importing Markets	Quantity (MW.h)	Revenue ($1000)
New Brunswick	Massachusetts	1 853 068	127 175
	Maine	4 799 097	151 696
Quebec	Maine	258	14
	Vermont	1 472 386	58 848
	New England	1 385 788	31 783
	New York	9 781 424	287 678
Ontario	Vermont	328 772	16 572
	New York	5 684 637	231 927
	Michigan	743 706	21 836
	Minnesota	328	9
Manitoba	Minnesota	5 737 470	89 840
	North Dakota	1 271 127	21 913
Saskatchewan	North Dakota	109 883	1 169
British Columbia	Alaska	317	47
	Washington	522 359	8 612
	Oregon	1 181 096	22 656
	California	399 447	14 251
Canada	United States	35 271 163	1 086 025

Source: National Energy Board.

Table 7.6. Provincial shares of Canadian exports, 1982-1986

	1982	1983	1984	1985	1986
			(per cent)		
New Brunswick	9	15	15	15	19
Quebec	26	28	30	23	36
Ontario	34	33	29	22	19
Manitoba	16	16	14	14	20
British Columbia	15	8	12	26	6
Canada	100	100	100	100	100

Source: Energy, Mines and Resources Canada.

Table 7.7. Canadian energy trade, 1982-1986

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			(millions of dollars)			
1982						
Exports	5 218	4 755	1 203	1 106	793	13 075
Imports	5 753	1	1 017	5	17	6 793
Balance	-535	4 754	186	1 101	776	6 282
1983						
Exports	6 338	3 958	1 247	1 249	430	13 222
Imports	4 221	0	941	6	15	5 183
Balance	2 117	3 958	306	1 243	415	8 039
1984						
Exports	7 580	3 886	1 851	1 376	875	15 568
Imports	4 919	1	1 203	10	15	6 148
Balance	2 661	3 885	648	1 366	860	9 420
1985						
Exports	9 239	3 912	2 030	1 425	822	17 518
Imports	5 242	0	1 023	9	28	6 302
Balance	3 997	3 912	1 007	1 416	794	11 216
1986						
Exports	5 854	2 483	1 869	1 086	842	12 134
Imports	4 379	0	874	9	31	5 293
Balance	1 475	2 483	995	1 077	811	6 841

Source: Statistics Canada, Exports by Commodities (65-004) and Imports by Commodities (65-007).

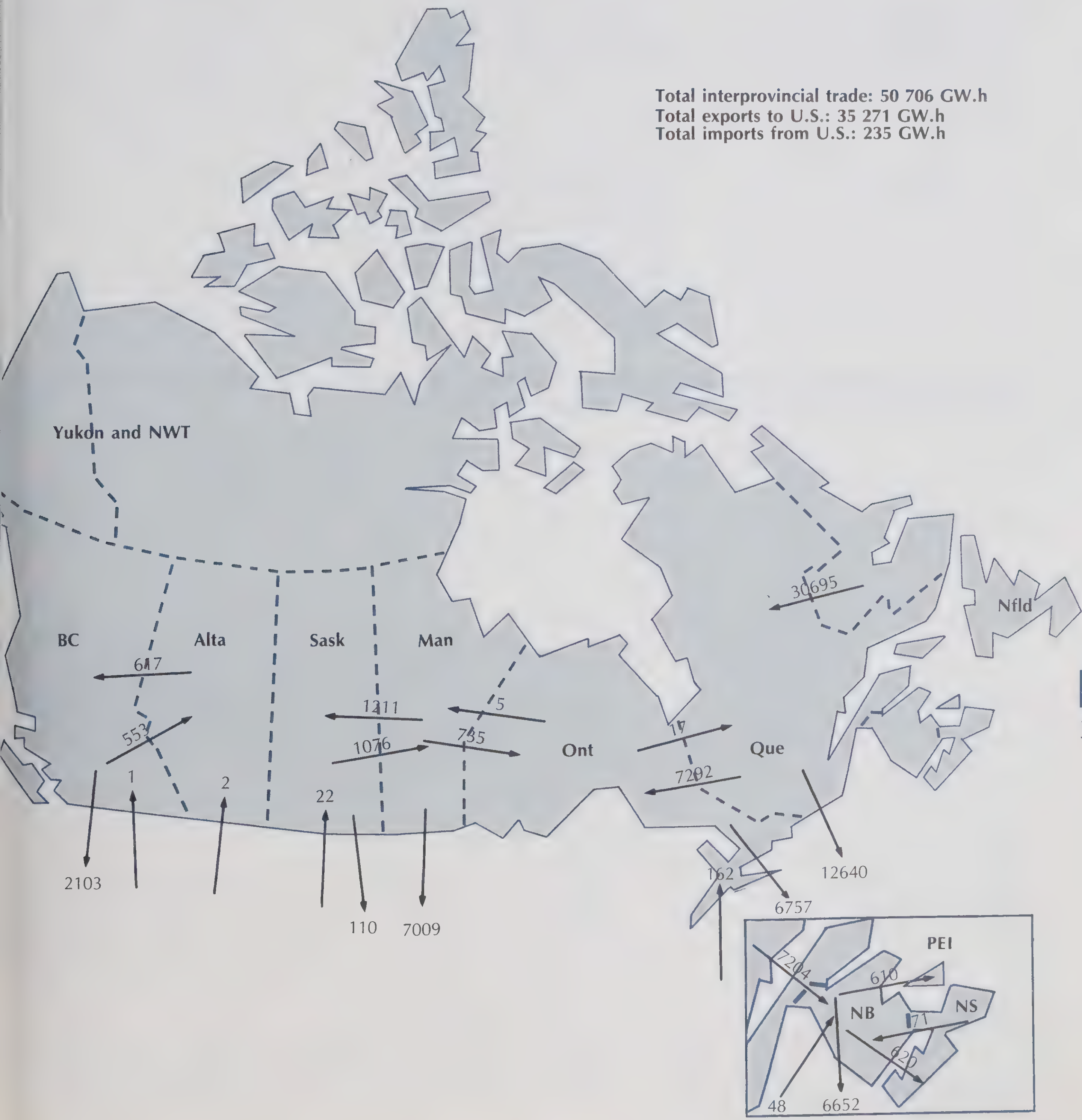
Table 7.8. Interprovincial transfers, 1982-1986

	1982	1983	1984	1985	1986
			(GW.h)		
Newfoundland to Quebec	35 777	31 234	36 042	31 837	30 695
Nova Scotia to New Brunswick	133	121	282	199	71
New Brunswick to Nova Scotia	216	722	301	350	620
New Brunswick to P.E.I.	476	519	539	575	610
New Brunswick to Quebec	0	5	0	2	0
Quebec to New Brunswick	3 613	3 993	4 306	5 827	7 204
Quebec to Ontario	5 773	5 379	7 362	8 664	7 292
Ontario to Quebec	55	52	62	39	17
Ontario to Manitoba	4	8	2	5	5
Manitoba to Ontario	1 072	957	940	968	735
Manitoba to Saskatchewan	1 388	1 598	1 625	1 556	1 211
Saskatchewan to Manitoba	1 084	1 206	1 298	1 233	1 076
Saskatchewan to Alberta	3	5	4	3	0
Alberta to Saskatchewan	0	4	0	0	0
Alberta to B.C.	189	194	262	243	617
B.C. to Alberta	443	342	298	275	553
Total	50 226	46 339	53 323	51 776	50 706

Source: Energy, Mines and Resources Canada.

The 252-MW Nipawin hydroelectric station, owned by Saskatchewan Power, entered service in September 1986.

igure 7.3. Electricity Trade, 1986. (GW.h)



35

Transmission

Canada

Total circuit length of electrical transmission in Canada, for lines rated at 100 kV and above, increased only 242 km in 1986. The total amount of Canadian transmission is now 114 150 km, and most of it (41 per cent) is in the range of 100 kV to 149 kV. Another 34 per cent is in the 150 kV to 299 kV range, while 16 per cent is between 300 kV and 599 kV. Newfoundland and Quebec are the only two provinces with transmission lines over 600 kV; their circuit length is 10 591 km, about 9 per cent of the Canadian total. Quebec has the greatest amount of electrical transmission, with 30 126 km, or 26.4 per cent of Canada's total. It is followed by Ontario with 24.5 per cent and British Columbia with 12.3 per cent. Transmission circuit length by province and voltage is reported in Table 8.1.

Provincial

The additions in 1986 were in Alberta, Quebec, and New Brunswick. Alberta Power Ltd. increased its 144-kV lines by 24 km and its 240-kV lines by 110 km. Hydro-Québec extended its 230-kV line by 7 km and its 735-kV lines by 99 km. New Brunswick Power increased its system by 9 km with the addition of one 138-kV line.

There are several transmission lines now under construction. Ontario is in the process of adding three 500-kV lines, with two scheduled to be completed in 1987 and the third in 1989. The new lines will increase Ontario's total circuit length by 448 km. Eight 240-kV lines are under construction in Alberta, and all are expected to be completed in 1987. The total circuit length of the lines will be 480 km.

Interprovincial

Table 8.2 presents the major provincial interconnections. There are 33 interties, with a total transfer capability of 9 895 MW.

Table 8.1. Transmission circuit length in Canada, 1986

	100 - 149 kV	150 - 199 kV	200 - 299 kV	300 - 399 kV	400 - 599 kV	600 kV and up	Total
Newfoundland	1 681	214	1 883	-	-	600	4 378
Prince Edward Island	168	-	-	-	-	-	168
Nova Scotia	1 586	-	1 204	173	-	-	2 963
New Brunswick	1 835	-	528	969	-	-	3 332
Quebec	7 608	2 178	3 626	6 723	-	9 991	30 126
Ontario	12 222	-	13 471	6	2 222	-	27 921
Manitoba	4 386	-	4 094	-	2 042	-	10 522
Saskatchewan	3 581	-	2 537	-	-	-	6 118
Alberta	8 142	133	5 027	-	356	-	13 658
British Columbia	4 264	179	3 854	403	5 264	-	13 964
Yukon	497	-	-	-	-	-	497
Northwest Territories	503	-	-	-	-	-	503
Canada	46 473 (41%)	2 704 (2%)	36 224 (32%)	8 274 (7%)	9 884 (9%)	10 591 (9%)	114 150 (100%)

Source: Statistics Canada Publication 57-202.
Energy, Mines and Resources Canada.

Although there were no new interprovincial lines under construction in 1986, one important interconnection was proposed. Saskatchewan Power Corporation and Alberta Power Ltd. signed an agreement to jointly construct a $41 million high-voltage-direct-current (HVDC) interconnection linking the electrical systems of the two provinces. This interconnection will run from Swift Current, Saskatchewan, to Empress, Alberta, and will enable Alberta and Saskatchewan to share 100 MW of generation resources and allow electric power sales between the two provinces. The interconnection will involve 175 km of 230-kV transmission line in Saskatchewan and 10 km of 138-kV line in Alberta. It will be the first Canadian link between the eastern and western power systems of North America. Construction of the interconnection, which is subject to regulatory approval in both provinces, is scheduled to begin in mid-1988 and be completed late the following year.

International

One new international transmission line was completed during 1986. This was a ±450 kV HVDC transmission line from Quebec to New Hampshire, with a power transfer capability of 690 MW. This transmission line may be upgraded to 2 000 MW by 1990.

There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 37 bulk power interties rated at 69 kV or higher, with a total power transfer capacity of 13 600 MW. These are presented in Table 8.3.

A 345-kV transmission line from Point Lepreau, New Brunswick, to Orrington, Maine, is planned by New Brunswick and is expected to be completed in 1989. The estimated power transfer capability would be 575 MW.

Table 8.2. Provincial interconnections at year end, 1986

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Saskatchewan - Manitoba	3 x 230	400
Manitoba - Ontario	2 x 230	260
	1 x 115	
Quebec - Ontario	4 x 230	1 300
	9 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x ±80(DC)	700
	1 x 230	150
	2 x 345	500
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - Prince Edward Island	1 x 138	200

** Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

Long Distance Transmission

Canada is a world leader in long distance electric power transmission, in both extra-high-voltage (EHV) alternating current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of the major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 700-kV class transmission system. This system now extends over 1 100 km from the Churchill Falls development in Labrador to Montreal; a comparable system of about the same distance extends from the James Bay development to Quebec load centres.

In Manitoba, pioneering work was done to develop the ±450 kV HVDC system that brought hydroelectric power from the Nelson River generating stations to

customers in southern Manitoba. Ontario and British Columbia also have extensive EHV systems in the 500-kV class. All of these systems are shown in Figure 8.1.

Such advances in Canadian transmission techniques have not only provided for long distance bulk transmission but also for extensive interconnections between neighbouring provinces (33 interties) and between Canada and the United States (over 100 interties). Figure 8.2 indicates the major provincial and international interconnections.

Table 8.3. Major interconnections between Canada and the United States*

Province	State	Voltage	Design Capability***
		(kV)	(MW)
New Brunswick	*Maine*	1 x 345	600
		1 x 138	60
		6 x 69	330
Quebec	*New York*	1 x 765	1 400
	New York	2 x 120	200
	Vermont	2 x 120	200
	New Hampshire	±450(DC)	690
*Ontario***	*New York*	230	470
		230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	230	535
		230	515
		345	710
		345	760
	Minnesota	120	35
Manitoba	*North Dakota*	230	150
	Minnesota	230	175
	Minnesota	500	1 000
Saskatchewan	*North Dakota*	230	150
British Columbia	*Washington*	230	350
		230	300
		2 x 500	1 400

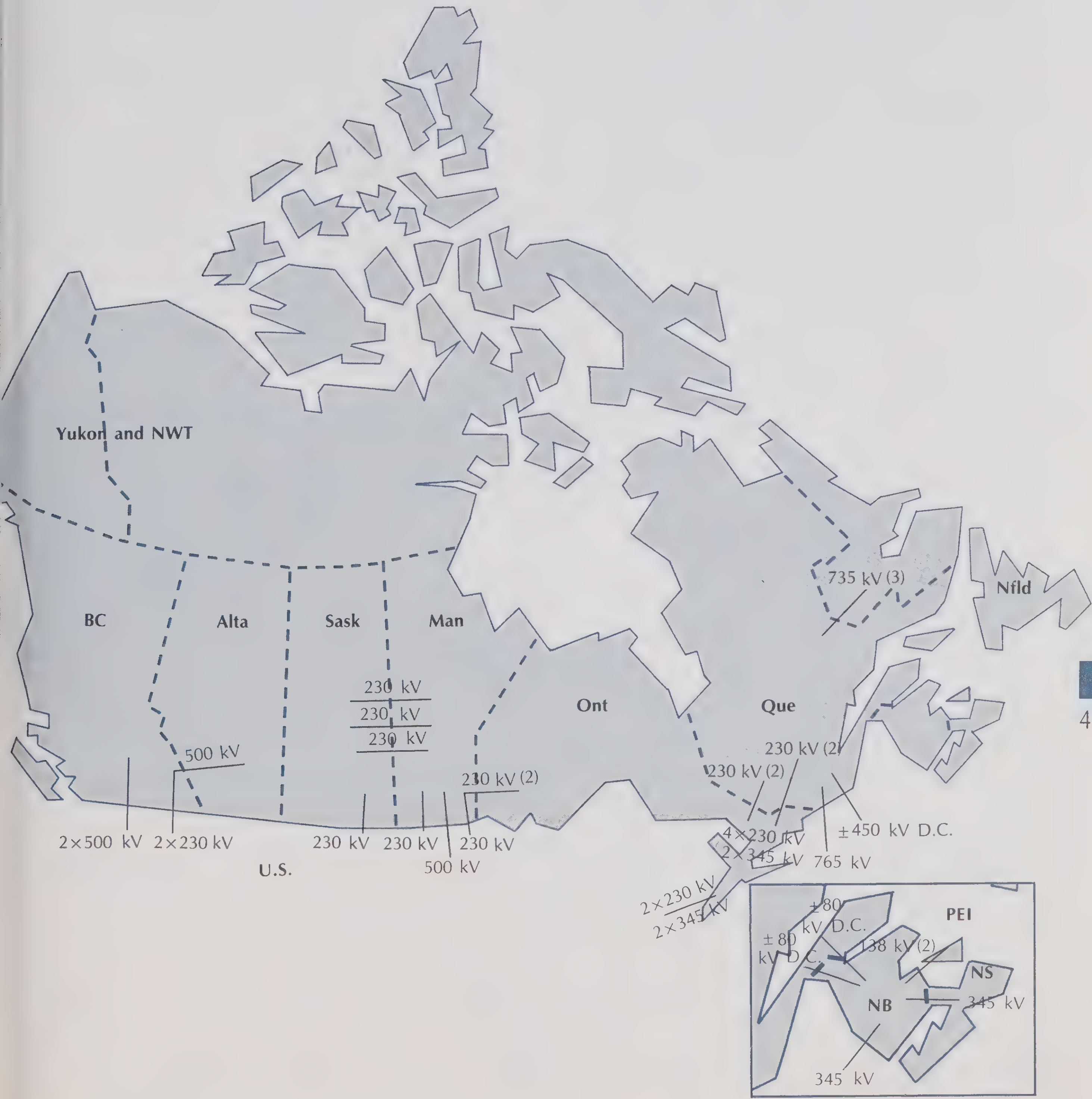
* *35 MW capacity or over.*
** *The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.*
*** *Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

*In June 1986 Newfoundland Light & Power repaired a 5 000-metre cable transmitting electricity to Bell Island in Conception Bay. An offshore supply vessel, the **Offshore Trader**, served as the "repair shop" for the six-day repair effort. In the foreground is a terminus for the cable; Bell Island is in the background.*

Figure 8.1. Major long distance transmission systems

Figure 8.2. Major provincial and international interconnections



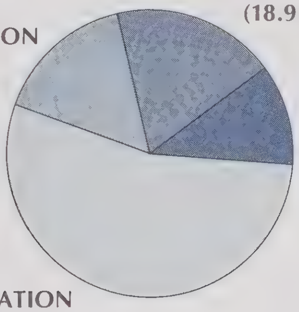
A Hydro-Québec employee conducts tests on a transmission line following a heavy snowfall on Îles-de-la-Madeleine.

Electric Utility Investment and Financing

Capital Investment

Electric utility investment in new facilities was $6.1 billion in 1986, slightly greater than the $5.9 billion spent in 1985. Table 9.1 illustrates the capital-intensive nature of electricity and its importance in the Canadian economy. Electric utility investment in Canada, as a share of total capital spending and GDP, has declined since l983, primarily because of the overcapacity that emerged at that time. However, the investment share of the industry in the energy sector increased in 1986, for the first time since 1983. Electric utility capital investment accounted for 43 per cent of total investment in the energy sector, as compared with 35 per cent in 1985.

Figure 9.1. Capital investment by function, 1986



Total Investment: $6.1 Billion

Table 9.1. Electric utility capital investment, 1977-1986

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Investment in electric power ($ billions)	4.9	5.9	6.4	6.1	7.3	8.4	7.8	6.3	5.9	6.1
*Energy share(%)**	56	58	53	42	40	39	42	37	35	43
*Economy share(%)**	10	11	10	8	8	10	9	7	6	6
*GDP share(%)**	2.2	2.4	2.3	2.0	2.1	2.2	1.9	1.4	1.2	1.2

** The figures indicate electric utility capital investment as a percentage of total energy investment, investment in the economy as a whole, and GDP.*

Source: Statistics Canada publications 61-205 and 11-003E.

Table 9.2. Capital investment by function, 1977-1986

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
	(millions of dollars)									
Generation	3 085	3 499	3 892	3 580	4 552	5 026	4 882	3 530	3 030	3 340
Transmission	907	1 290	1 266	1 114	1 387	1 436	1 270	1 158	861	946
Distribution	519	499	570	703	646	937	766	834	1 038	1 158
Other	373	648	636	712	734	1 009	852	818	974	680
Total	4 884	5 936	6 364	6 109	7 319	8 408	7 770	6 340	5 903	6 124

Source: Energy, Mines and Resources Canada.

Of the $6.1 billion capital investment in 1986, it is estimated that about 55 per cent of the total was for generation, 19 per cent for distribution, and 15 per cent for transmission. Figure 9.1 shows electric utility capital investment by function in 1986. Table 9.2 summarizes capital investment by function for the period 1977-86. During the past 10 years, the generation component constituted approximately 59 per cent of the total capital investment.

Table 9.3 reports the capital investment of 14 major electric utilities in 1985 and 1986. With the exception of Hydro-Québec, Saskatchewan Power, TransAlta Utilities, and BC Hydro, all major utilities increased their capital investment in 1986. Ontario Hydro accounted for about 43 per cent of total utility capital investment in 1986, most of which was related to the ongoing construction of the Darlington nuclear station.

Financing

Electric utilities in Canada normally borrow a proportion of their capital requirements from the United States, Western Europe, and Japan. Table 9.4 shows that the outstanding long-term debt of major utilities in Canada was $62 billion as of December 31, 1985. It is estimated that about $32 billion (52 per cent) was borrowed from international markets and $30 billion (48 per cent) from the domestic market. Of the total $32 billion borrowed internationally, it is estimated that about $29 billion (91 per cent) came from the United States.

Among the 14 major electric utilities, Newfoundland and Labrador Hydro, NB Power, Hydro-Québec, Ontario Hydro, Manitoba Hydro, and BC Hydro are heavily dependent on foreign sources to finance their power projects. All six utilities are provincially owned.

Table 9.5 indicates that in 1985

Table 9.3. Capital investment by major electric utility

	1985	1986	Year-over-year change
	(millions of current dollars)		(per cent)
Newfoundland and Labrador Hydro	26	28	7.7
Newfoundland Light & Power	33	33	0.0
Maritime Electric Co. Ltd.	5	10	200.0
Nova Scotia Power	87	124	42.5
NB Power	78	80	2.6
Hydro-Québec	1 615	1 537	-4.8
Ontario Hydro	2 617	2 641	0.9
Manitoba Hydro	185	248	34.1
Saskatchewan Power	251	162	-35.5
Alberta Power	140	157	12.1
Edmonton Power	97	175	80.4
TransAlta Utilities	254	229	-9.8
BC Hydro	194	148	-23.7
Northern Canada Power Commission	4	12	300.0
Canada	5 586	5 584	-0.1

Source: Energy, Mines and Resources Canada.

Table 9.4. Major electric utility long-term debt and sources of financing, 1985

	Long-Term Debt ($ millions)	Sources of Long-Term Debt Financing Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 411	42	58
Newfoundland Light & Power	121	92	8
Maritime Electric Co. Ltd.	27	100	0
Nova Scotia Power	1 172	71	29
NB Power	2 163	38	62
Hydro-Québec	20 123	42	58
Ontario Hydro	22 518	53	47
Manitoba Hydro	2 524	30	70
Saskatchewan Power	1 778	59	41
Alberta Power	343	100	0
Edmonton Power	577	100	0
TransAlta Utilities	1 094	94	6
BC Hydro	8 209	38	62
Northern Canada Power Commission	235	100	0
Canada	62 295	48	52

Source: Energy, Mines and Resources Canada.

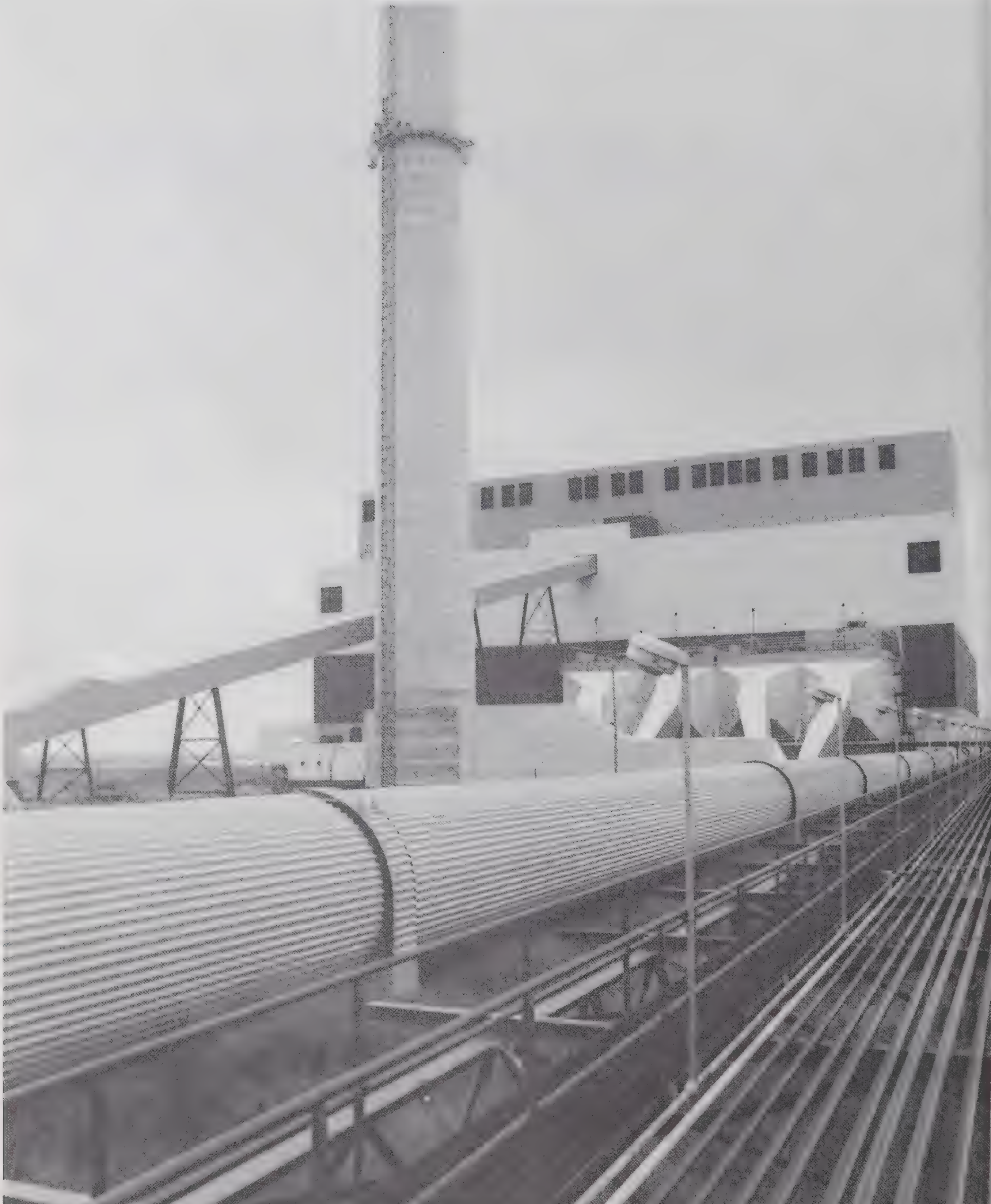
Canadian publicly owned electric utilities had debt ratios ranging from 65 per cent for Winnipeg Hydro to about 97 per cent for Saskatchewan Power. The debt ratios for investor-owned utilities ranged from 29 per cent to 47 per cent.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned utilities in the United States. As Table 9.5 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 71 per cent, 83 per cent, and 100 per cent, respectively. The selected American investor-owned utilities had debt ratios ranging from 36 per cent to 53 per cent.

Table 9.5. Comparison of Canadian and U.S. electric utility debt ratios

	1984	1985
CANADA		
Publicly owned utilities		
Newfoundland and Labrador Hydro	91	90
Nova Scotia Power	94	95
NB Power	89	88
Hydro-Québec	76	77
Ontario Hydro	83	83
Manitoba Hydro	97	96
Winnipeg Hydro	64	65
Saskatchewan Power	95	97
Edmonton Power	84	79
BC Hydro	86	86
Investor-owned utilities		
Newfoundland Light & Power	47	47
Maritime Electric	38	37
TransAlta Utilities Corporation	33	33
Alberta Power	31	29
UNITED STATES		
Publicly owned utilities		
Tennessee Valley Authority	84	83
Bonneville Power Administration	100	100
Power Authority of the State of New York	69	71
Investor-owned utilities		
Boston Edison Company	50	51
Northeast Utilities	52	53
Consolidated Edison Company of New York	34	36
Niagara Mohawk Power Corporation	46	46
American Electric Power Company	54	53
Northern States Power Company	46	46
Washington Water Power Company	48	44
Pacific Gas and Electric Company	46	48

Source: Energy, Mines and Resources Canada.



The 380-MW Sheerness generating station in southeastern Alberta was officially opened on June 20, 1986. The coal-fired station i jointly owned by the province's two investor-owned utilities, Alberta Power Ltd. and TransAlta Utilities Corporation. Electrostat precipitators, shown above at the back of the plant, remove 99 percent of the flyash that is produced as the coal burns.

ectricity Supply Costs

he unit cost of supplying dditional electricity increased pidly during the period 1974-82. owever, cost increases have ioderated significantly since then. djusted for inflation, recent icreases in the cost of electricity ave been small, and this is xpected to be the case for the ext several years.

n the 1974-82 period, there were vo basic reasons for the rapid icreases in the cost of electricity: ie high rate of inflation, with an verage increase of 10 per cent nnually; and the increased cost of ossil fuels, with an average annual icrease of 18 per cent. High levels f inflation affect the electric utility ndustry by increasing the cost of onstructing additional facilities nd by increasing the cost of orrowed funds.

he average interest rate on new ong-term utility debt for the period 967-86 is shown in Table 10.1. nterest rates started to rise in 974, which coincided with the irst oil crisis, and reached a peak n 1981, after which they dropped ubstantially. In 1986, interest rates iveraged 10.5 per cent.

The indices of electric utility construction costs, presented in Table 10.1, show that increases in both hydro and steam construction costs between 1969 and 1976 exceeded increases in the CPI. However, since 1977 increases in the CPI have consistently exceeded increases in hydro and steam construction costs, with some minor exceptions for steam in 1979-80 and 1986, and hydro in 1981. The average increase in construction costs during the period 1967-86 was 7.4 per cent for hydro projects and 7.8 per cent for thermal stations, compared to 7.3 per cent for the CPI. In general, electricity construction costs tend to parallel the CPI.

Increases in fossil-fuel costs since 1969 are summarized in Table 10.2. Fuel costs for electricity generation were generally stable until the oil crisis of 1973, after which they began to rise. For Canada as a whole, the fuel cost per kW.h of electricity generated from fossil fuels increased more than four times between 1973 and 1985, from 3.1 mills to 13.5 mills. The increase in the cost of fuel from oil generation was much more dramatic, growing from 7.1 mills to 68.02 mills per kW.h during the same period, an average annual increase of 21 per cent. The cost of oil-fired generation declined substantially in 1986, because of the collapse of world oil prices.

The unit cost of coal used to generate electricity varies between regions of the country and depends on the type of coal used, its source, and the percentage of total energy supply derived from fossil-fuel plants. The unit fuel cost of electricity generated from western coal increased from 1.4 mills per kW.h in 1973 to 6.6 mills per kW.h in 1985. In the same period, the fuel cost of eastern coal-fired generation increased from 4.7 mills to 26.1 mills. Western coal used for electricity generation is produced domestically, while a large proportion of eastern coal is imported.

The unit fuel cost of electricity generated from natural gas increased substantially between 1973 and 1985, from 3.7 mills per kW.h to 31.8 mills per kW.h, an average increase of about 20 per cent. Over the last 10 years, nuclear-generated electricity has

Table 10.1. Inflation, interest rates, and construction costs, 1967-1986

	Average Interest Rate	Increase in Construction Cost		CPI
		Hydro	Steam	
	(per cent)			
1967	6.7	3.6	1.1	3.5
1968	7.8	4.2	2.8	4.7
1969	8.6	5.7	6.8	4.5
1970	9.3	6.6	7.4	3.3
1971	8.5	4.6	6.0	2.9
1972	8.4	6.3	6.1	4.8
1973	8.6	9.2	9.2	7.6
1974	10.2	18.8	20.5	10.9
1975	10.7	14.3	13.4	10.8
1976	10.4	8.9	10.0	7.5
1977	9.6	5.9	7.9	8.0
1978	10.0	7.7	8.7	9.0
1979	10.9	8.7	11.0	9.2
1980	13.3	10.0	11.6	10.2
1981	16.3	13.7	11.9	12.5
1982	15.9	7.2	6.8	10.8
1983	12.8	4.6	4.1	5.8
1984	12.5	3.2	2.8	4.4
1985	11.7	1.7	3.8	4.0
1986	10.5	2.8	4.8	4.1

Source: Interest rates - McLeod Young Weir Ltd.
Construction costs and CPI - Statistics Canada publications 62-007 and 62-00l.

had the lowest unit fuel cost in Canada. In 1985, it cost 4.7 mills per kW.h, compared with 68.0 mills for petroleum, 31.8 mills for natural gas, and 6.6 mills for western coal.

Pricing

The average revenue from electricity sales for each province is provided in Table 10.3. Income statements for the major utilities are summarized in Table 10.4. Because electricity rates are regulated to cover costs, the average revenue per unit of electricity began to increase significantly in 1975, with the escalation in the cost of electricity generation. The average annual growth in unit revenue for Canada as a whole was 10.9 per cent during the period 1976-85. The national inflation rate, as measured by the CPI, was 8.2 per cent over the same period.

Electricity costs differ across the country primarily because of differences in generation mix and the size and geographic distribution of the population being served. Table 10.5 gives monthly electricity costs for selected Canadian cities. Winnipeg had the lowest electricity costs in Canada in all three sectors, while Charlottetown had the highest. Table 10.6 details the average annual rate increases for customers in each province since 1977. In 1986, there were three electric utilities with negative rate changes. In the case of Newfoundland and Labrador Hydro, the rate decline of 1.7 per cent was due to fuel adjustment charges. Effective July 1, 1986, a

Table 10.2. Cost of fuel for electricity generation, 1969-1985

	Eastern Coal	Western Coal	Petroleum	Natural Gas	Uranium	Total Fuels
	(mills/kW.h)					
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54

Source: Calculated from Electric Power Statistics, *Statistics Canada, catalogue 57-202, various issues.*

Table 10.3. Average revenue from electricity sales by province, 1976-1985

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
	(current cents/kW.h)									
Nfld.	1.4	1.7	2.0	2.2	2.3	2.8	3.6	3.7	3.9	4.7
P.E.I.	5.1	5.9	6.4	7.2	8.1	10.0	12.0	12.4	12.8	12.9
N.S.	2.8	3.9	4.4	4.6	4.5	4.9	5.9	6.9	7.5	7.3
N.B.	2.0	2.4	3.2	3.7	4.1	4.8	5.1	5.3	5.5	5.8
Que.	1.4	1.5	1.7	2.0	2.2	2.6	3.1	3.3	3.4	3.5
Ont.	1.8	2.3	2.4	2.6	2.9	3.2	3.6	3.9	4.2	4.5
Man.	1.7	1.9	2.3	2.7	2.8	2.8	2.9	3.0	3.4	3.6
Sask.	2.1	2.4	2.7	2.7	2.9	3.6	4.0	4.2	4.5	4.8
Alta.	2.4	2.7	3.1	3.2	3.4	4.1	4.9	5.2	5.4	5.4
B.C.	1.8	2.1	2.2	2.4	2.6	3.0	3.8	3.8	4.1	4.4
Yukon	3.5	4.1	4.4	4.9	5.3	6.7	8.3	8.3	8.6	9.0
N.W.T.	5.2	6.9	7.7	9.0	10.0	11.5	14.8	17.9	16.7	16.3
Canada	1.7	2.0	2.3	2.5	2.8	3.1	3.7	3.9	4.1	4.3

Source: Statistics Canada publication 57-202.

Table 10.4. Major electric utilities' statements of income, 1985

	Total Revenue	O & M	Fuel Costs	Power Purchased	Depre-ciation	Taxes	Interest	Exchange Losses	Other Costs	Net Income
	(millions of current dollars)									
Newfoundland and Labrador Hydro	331	50	95	1	23	-	121	-	-	41
Newfoundland Light & Power	244	36	-	143	15	14	15	-	-	21
Maritime Electric Co. Ltd.	64	14	-	33	3	5	4	-	-	5
Nova Scotia Power	492	64	193	16	47	5	142	-	37	(12)
NB Power	894	91	156	193	76	-	266	-	86	26
Hydro-Québec	4 492	1 163	-	122	419	246	2 075	258	-	209
Ontario Hydro	4 625	966	968	163	655	87	1 325	176	(75)	360
Manitoba Hydro	553	192	-	9	75	-	244	81	(78)	30
Winnipeg Hydro	80	23	-	30	3	1	6	-	1	16
Saskatchewan Power	837	228	333	-	78	-	197	-	-	1
Alberta Power	324	22	128	-	31	46	36	-	-	61
Edmonton Power	263	37	-	115	17	20	20	1	(10)	63
TransAlta Utilities	836	165	-	15	116	207	137	-	15	181
BC Hydro	2 094	293	316	12	213	321	872	51	4	12
Northern Canada Power Commission	89	54	-	-	11	-	22	-	7	(5)
Canada	16 218	3 398	2 189	852	1 782	952	5 482	567	(13)	1 009

Source: Obtained from electric utilities' annual reports, 1985.

cost-of-commodity clause ceased to be a part of Maritime Electric's schedule of rates, resulting in the 3.75 per cent decrease shown in Table 10.6. The reduction in Alberta Power's rates was the result of the Alberta Electric Energy Marketing Agency rebate, the provincial income tax rebate, and rate restructuring.

Figure 10.1 illustrates the movement of the electricity, oil, and natural gas components of the CPI, as well as the CPI itself. It indicates that the electricity price component increased more slowly than or equal to the rate of increase of the CPI for the period 1971-76. Since 1977, the electricity price index has been consistently greater than the CPI; however, the increase has been more gradual than for the oil and gas price indices.

Table 10.5. Monthly electricity costs for selected Canadian cities, January 1986

Sector	**Residential**	**Commercial**	**Industrial**
Billing Demand (kW)	-	100	1000
Consumption (kW.h)	1000	25 000	400 000
	($)		
St. John's	70.01	1 769.98	22 101.29
Charlottetown	117.88	3 365.81	48 385.70
Halifax	65.72	2 047.21	21 134.61
Moncton	64.50	2 006.30	20 450.00
Montreal	40.04	1 367.80	15 166.00
Ottawa	46.89	1 223.78	17 393.78
Toronto	52.89	1 262.53	19 730.00
Winnipeg	38.35	1 013.60	11 505.19
Regina	47.26	1 497.20	19 009.70
Calgary	51.23	1 469.26	16 963.00
Edmonton	51.50	1 563.60	19 980.84
Vancouver	52.38	1 308.05	15 766.15
Whitehorse	69.30	2 205.00	-
Yellowknife	90.79	2 669.00	-

Source: Statistics Canada publication 57-203.

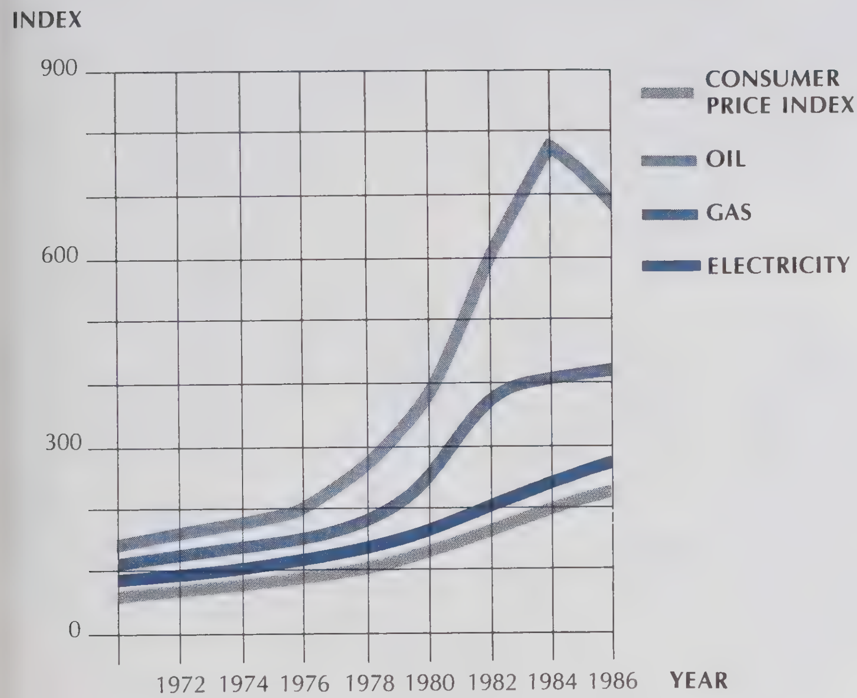
Table 10.6. Average annual rate increases, 1977-1986

	Rate Changes (%): Average of all Customer Classes									
	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Newfoundland and Labrador Hydro	8.4	25.0	-	19.0	15.8	-	18.2	-	-	-1.7
Newfoundland Light & Power	9.8	21.2	12.4	11.8	14.6	-	12.0	-	-	8.66
Maritime Electric Co. Ltd.	17.0	13.0	-	13.1	21.4	-**	-**	-**	3.7	-3.75
Nova Scotia Power	43.0	14.0	12.5	-(b)	-	-	36.6	-	-	-
NB Power	16.6	9.9	7.9	7.8	9.8	-	8.8	6.2	4.6	-
Hydro-Québec	9.9	18.7	13.7	13.3	10.6	16.3	7.3	4.0	4.0	5.4
Ontario Hydro	25.6	5.7	7.7	7.3	10.0	10.0	8.2	7.5	8.6	4.0
Manitoba Hydro	15.0	14.9	14.4	-(a)	-	-	9.5	7.9	5.0	2.8
Saskatchewan Power	17.0	3.3	8.3	7.9	16.1	-	12.6	9.2	-	7.5
Edmonton Power	6.0	8.1	-	26.0	12.0	13.2	8.0	5.0	6.7	-
TransAlta Utilities	14.7	15.6	7.5	-	13.0	4.0	15.0	-	1.7	6.1
Alberta Power	20.2	-	-	12.3	28.9	-11.6*	2	-	-4.3	-8.6
BC Hydro	12.1	13.4	5.5	7.6	2.6	20.0*	6.0	6.5	3.8	1.84

(a) The provincial government froze rates from 1979 until 1983.
(b) The provincial government froze rates in 1980.
** Based on residential category. (Alberta Power's reduction in rates is a result of the Alberta Electric Energy Marketing Agency rebate.)*
*** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.*

Source: Energy, Mines and Resources Canada.

Figure 10.1. Price Indices, 1971-1986



Ontario Hydro employees lower a turbine diaphragm into position during the construction of Unit 7 of the Bruce B Nuclear generating station.

APPENDIX

Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1986

Year	Installed Capacity					Electrical Energy Consumption	Average Demand	Peak Demand		Reserve Margin	Load Factor
	Thermal			Hydro	Total						
	Conventional	Nuclear	Sub-Total								
	(MW)					(GW.h) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 657	23 049	109 302	12 477	17 264	5 785	34	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 537	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	27 853	5 866	33 719	47 919	81 638	340 069	38 821	59 170	22 464	38	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	67 325	27 864	41	65
1985r	30 885	9 813	40 698	56 048	96 746	406 038	46 351	72 145	24 601	34	64
1986p	30 535	10 984	41 519	56 849	98 368	421 856	48 126	73 470	24 898	34	66

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81: Statistics Canada Publication, 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr).

(c) Statistics Canada Publication 57-204.

(d) Reserve margin = (Installed capacity - Peak demand) / Peak demand

(e) Load Factor = Average demand ÷ Peak demand.

p Preliminary figures. r Revised figures.

Source: Statistics Canada.
Energy, Mines and Resources Canada.

Table A2. Installed and proposed generating capacity, 1986

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	(MW)				
Newfoundland	6 417	0	757	7 174	7.29
Prince Edward Island	0	0	122	122	.12
Nova Scotia	366	0	1 989	2 355	2.39
New Brunswick	903	635	1 896	3 434	3.49
Quebec	25 812	638	1 111	27 561	28.02
Ontario	7 172	9 711	13 523	30 406	30.91
Manitoba	3 641	0	501	4 142	4.21
Saskatchewan	829	0	1 991	2 820	2.87
Alberta	734	0	6 864	7 598	7.72
British Columbia	10 844	0	1 599	12 443	12.65
Yukon	82	0	41	123	.13
Northwest Territories	49	0	141	190	.19
Canada (Totals as of December 31, 1986)	56 849	10 984	30 535	98 368	100.00
Percentage of total	57.79	11.17	31.04	100.00	
Net additions during 1986	969	1 346	430	2 745	
Planned additions 1987	0	830	104	934	

Source: Energy, Mines and Resources Canada.

Table A3. Conventional thermal capacity by principal fuel type. Preliminary figures as of December 31, 1986 (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other*	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other*	Total
Nfld.	0	505	0	0	505	170	0	170	82	0	82	0	757	0	0	757
P.E.I.	0	70	0	0	70	41	0	41	11	0	11	0	122	0	0	122
N.S.	954	829	0	0	1 783	205	0	205	1	0	1	954	1 035	0	0	1 989
N.B.	285	1 561	0	22	1 868	23	0	23	5	0	5	285	1 589	0	22	1 896
Que.	0	628	0	10	638	363	0	363	110	0	110	0	1 101	0	10	1 111
Ont.	9 145	2 295	1 365	90	12 895	437	181	618	4	6	10	9 145	2 736	1 552	90	13 523
Man.	419	0	4	23	446	24	0	24	31	0	31	419	55	4	23	501
Sask.	1 680	0	106	36	1 822	0	162	162	7	0	7	1 680	7	268	36	1 991
Alta.	4 859	65	1 264	107	6 295	0	524	524	14	31	45	4 859	79	1 819	107	6 864
B.C.	0	124	1 038	190	1 352	100	54	154	76	17	93	0	300	1 109	190	1 599
Yukon	0	0	0	0	0	0	0	0	41	0	41	0	41	0	0	41
N.W.T.	0	0	0	0	0	0	0	0	141	0	141	0	141	0	0	141
Canada	17 342	6 077	3 777	478	27 674	1 363	921	2 284	523	54	577	17 342	7 963	4 752	478	30 535

** Mainly wood wastes and black liquor.*
Numbers may not total because of rounding.

Source: Energy, Mines and Resources Canada.

Table A4. Electrical energy production by principal fuel type (GW.h)

	Conventional Thermal*							% of Total	% Generated By	
	Coal	Oil	Gas	Total	Nuclear	Hydro	Total	Generation	Utilities	Industry
Newfoundland	0	1 278	0	1 278	0	39 129	40 407	8.86	98.90	1.10
Prince Edward Island	0	12	0	12	0	0	12	.00	100.00	.00
Nova Scotia	5 748	662	0	6 410	0	1 001	7 411	1.63	95.06	4.94
New Brunswick	1 365	2 454	0	3 819	5 227	3 146	12 192	2.67	93.91	6.09
Quebec	0	140	0	140	3 792	144 328	148 260	32.53	88.28	11.72
Ontario	25 950	12	0	25 962	58 213	41 050	125 225	27.47	96.89	3.11
Manitoba	163	37	12	212	0	23 840	24 052	5.28	99.72	.28
Saskatchewan	8 106	7	36	8 149	0	3 764	11 913	2.61	96.88	3.12
Alberta	31 784	18	1 114	32 916	0	1 800	34 716	7.62	91.36	8.64
British Columbia	0	280	1 569	1 849	0	48 923	50 772	11.14	78.12	21.88
Yukon	0	22	0	22	0	315	337	.07	100.00	.00
N.W.T.	0	188	0	188	0	347	535	.12	95.14	4.86
Canada	73 116	5 110	2 731	80 957	67 232	307 643	455 832	100.00	94.52	5.48

** The conventional thermal breakdown is estimated.*

Source:Statistics Canada.
Energy, Mines and Resources Canada.

Table A5. Provincial electricity imports and exports (GW.h)

Province	Year	Interprovincial Trade			International Trade*			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Newfoundland	1986	30 695	-	30 695	-	-	-	30 695
	1985	31 837	-	31 837	-	-	-	31 837
	1984	36 043	-	36 043	-	-	-	36 043
	1983	31 234	-	31 234	-	-	-	31 234
Prince Edward Island	1986	-	610	-610	-	-	-	-610
	1985	-	575	-575	-	-	-	-575
	1984	-	539	-539	-	-	-	-539
	1983	-	519	-519	-	-	-	-519
Nova Scotia	1986	71	611	-540	-	-	-	-540
	1985	199	350	-151	-	-	-	-151
	1984	282	301	-19	-	-	-	-19
	1983	121	723	-602	-	-	-	-602
New Brunswick	1986	1 230	7 275	-6 045	7 008	424	6 584	539
	1985	927	6 026	-5 099	6 093	12	6 081	982
	1984	841	4 588	-3 747	5 657	17	5 640	1 893
	1983	1 245	4 112	-2 867	5 265	24	5 241	2 374
Quebec	1986	14 496	30 712	-16 216	12 674	35	12 639	-3 577
	1985	14 491	31 878	-17 387	9 581	3	9 578	-7 809
	1984	11 668	36 105	-24 437	11 250	8	11 242	-13 195
	1983	9 371	31 290	-21 919	10 128	8	10 120	-11 799
Ontario	1986	22	8 027	-8 005	7 957	1 693	6 264	-1 441
	1985	44	9 632	-9 588	10 563	1 701	8 862	-726
	1984	64	8 302	-8 238	11 370	913	10 457	2 219
	1983	59	6 336	-6 277	12 207	369	11 838	5 561
Manitoba	1986	1 946	1 087	859	6 989	12	6 977	7 836
	1985	2 524	1 238	1 286	5 660	45	5 615	6 901
	1984	2 565	1 301	1 264	5 057	43	5 014	6 278
	1983	2 555	1 213	1 342	5 994	19	5 975	7 317

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Table A5. Provincial electricity imports and exports (GW.h) (Continued)

Province	Year	Interprovincial Trade			International Trade*			Total Net
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	Exports
Saskatchewan	1986	1 076	1 210	-134	151	64	87	-47
	1985	1 236	1 556	-320	163	93	70	-250
	1984	1 302	1 625	-323	86	66	20	-303
	1983	1 210	1 601	-391	81	84	-3	-394
Alberta	1986	617	555	62	-	3	-3	59
	1985	243	278	-35	-	2	-2	-37
	1984	262	302	-40	-	2	-2	-42
	1983	198	346	-148	-	2	-2	-150
British Columbia	1986	553	617	-64	4 156	2 727	1 429	1 365
	1985	275	243	32	10 956	837	10 119	10 151
	1984	298	262	36	8 015	1 294	6 721	6 757
	1983	341	196	145	4 633	2 251	2 382	2 527
Yukon	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
Northwest Territories	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
Canada	1986	-	-	-	38 934	4 957	33 977	33 977
	1985	-	-	-	43 016	2 693	40 323	40 323
	1984	-	-	-	41 436	2 343	39 093	39 093
	1983	-	-	-	38 308	2 757	35 551	35 551

* *Includes exchanges.*

Source: Statistics Canada.

Table A6. Electricity exports by utility, 1986

Exporting Utility/ Company	Importing State/Group	Revenue ($000)	Quantity (GW.h)
Fraser Inc.	Maine	16 530	376
Maine & New Brunswick Electrical Power Co. Ltd.	Maine	1 557	119
NB Power	Maine	133 609	4 304
NB Power	Massachusetts	127 175	1 853
Hydro-Québec	Maine	14	N
Hydro-Québec	Vermont	58 848	1 472
Hydro-Québec	NEPOOL	31 783	1 386
Hydro-Québec	New York	287 677	9 781
St. Lawrence Power Co.	New York	7 976	299
Ontario Hydro	Vermont	16 572	329
Ontario Hydro	New York	208 180	4 959
Ontario Hydro	Michigan	21 836	743
Canadian Niagara Power Co.	New York	15 771	427
Boise Cascade Canada Ltd.	Minnesota	9	N
Manitoba Hydro	Minnesota	89 840	5 737
Manitoba Hydro	North Dakota	21 913	1 271
Saskatchewan Power Corp.	North Dakota	1 169	110
Cominco Ltd.	Washington	1 501	166
West Kootenay Power and Light Co.	Washington	1	N
BC Hydro	Washington	7 111	356
BC Hydro	Oregon	22 656	1 181
BC Hydro	California	14 251	399
BC Hydro	Alaska	47	N

N = negligible

Source: Energy, Mines and Resources Canada.

Table A7. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1985	504.60	170.39	81.67	-	756.66	6 416.20	7 172.86
Additions 1986	-	-	-	-	-	.51	.51
Total end 1986	504.60	170.39	81.67	-	756.66	6 416.71	7 173.37
PRINCE EDWARD ISLAND							
Total end 1985	70.50	40.85	11.14	-	122.49	-	122.49
Additions 1986	-	-	-	-	-	-	-
Total end 1986	70.50	40.85	11.14	-	122.49	-	122.49
NOVA SCOTIA							
Total end 1985	1 783.09	205.00	0.60	-	1 988.69	366.40	2 355.09
Additions 1986	-	-	-	-	.00	-	.00
Total end 1986	1 783.09	205.00	0.60	-	1 988.69	366.40	2 355.09
Additions proposed							
1991	150.00	-	-	-	150.00	-	150.00
1994	150.00	-	-	-	150.00	-	150.00
1995	300.00	-	-	-	300.00	-	300.00
2000	300.00	-	-	-	300.00	-	300.00
2003	300.00	-	-	-	300.00	-	300.00
2006	300.00	-	-	-	300.00	-	300.00
Total end 2006	3 283.09	205.00	0.60	-	3 488.69	366.40	3 855.09
NEW BRUNSWICK							
Total end 1985	1 868.08	23.38	4.84	635.00	2 531.30	903.03	3 434.33
Additions 1986	-	-	-	-	-	-	-
Total end 1986	1 868.08	23.38	4.84	635.00	2 531.30	903.03	3 434.33
Additions proposed							
1993	335.00	-	-	-	335.00	-	335.00
1998	335.00	-	-	-	335.00	-	335.00
Total end 1998	2 538.08	23.38	4.84	635.00	3 201.30	903.03	4 104.33

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
QUEBEC							
Total End 1985	637.75	362.88	110.36	638.00	1 748.99	24 928.53	26 677.52
Additions 1986	-	-	-	-	.00	883.50	883.50
Total End 1986	637.75	362.88	110.36	638.00	1 748.99	25 812.03	27 561.02
Additions Proposed							
1989	-	-	-	-	.00	980.00	980.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	-	.00	-	.00
1992	-	-	-	-	.00	950.00	950.00
1993	-	-	-	-	.00	950.00	950.00
1994	-	-	-	-	.00	-	.00
1995	-	500.00	-	-	500.00	918.00	1 418.00
1996	-	-	-	-	.00	1 033.00	1 033.00
1997	-	-	-	-	.00	1 157.00	1 157.00
1998	-	200.00	-	-	200.00	1 013.00	1 213.00
1999	-	-	-	-	.00	1 187.00	1 187.00
2000	-	-	-	-	.00	1 704.00	1 704.00
2001	-	-	-	-	.00	212.00	212.00
2002	-	300.00	-	-	300.00	321.00	621.00
2003	-	300.00	-	-	300.00	-	300.00
Total End 2003	637.75	1 662.88	110.36	638.00	3 048.99	36 237.03	39 286.02
ONTARIO							
Total end 1985	12 894.80	617.57	9.52	8 182.00	21 703.89	7 171.53	28 875.42
Additions 1986	-	-	-	1 529.00	1 529.00	-	1 529.00
Total end 1986	12 894.80	617.57	9.52	9 711.00	23 232.89	7 171.53	30 404.42
Additions proposed							
1987	-	104.00	-	830.00	934.00	-	934.00
1988	-	-	-	881.00	881.00	-	881.00
1989	-	-	-	881.00	881.00	43.00	924.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	881.00	881.00	-	881.00
1992	-	-	-	881.00	881.00	-	881.00
Total end 1992	12 894.80	721.57	9.52	14 065.00	27 690.89	7 214.53	34 905.42

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
MANITOBA							
Total end 1985	445.80	23.80	30.74	-	500.34	3 641.10	4 141.44
Additions 1986	-	-	-	-	.00	-	.00
Total end 1986	445.80	23.80	30.74	-	500.34	3 641.10	4 141.44
Additions proposed							
1990	-	-	-	-	.00	256.00	256.00
1991	-	-	-	-	.00	640.00	640.00
1992	-	-	-	-	.00	384.00	384.00
1997	-	-	-	-	.00	130.00	130.00
1998	-	-	-	-	.00	520.00	520.00
1999	-	-	-	-	.00	650.00	650.00
Total end 1999	445.80	23.80	30.74	-	500.34	6 221.10	6 721.44
SASKATCHEWAN							
Total end 1985	1 921.76	154.92	6.20	-	2 082.88	744.50	2 827.38
Additions 1986	-	50.00	-	-	50.00	85.00	135.00
Total end 1986	1 921.76	204.92	6.20	-	2 132.88	829.50	2 962.38
Additions proposed							
1988	-	100.00	-	-	100.00	-	100.00
1989	-	100.00	-	-	100.00	-	100.00
1991	280.00	-	-	-	280.00	-	280.00
1994	-	-	-	-	.00	85.00	85.00
1995	280.00	-	-	-	280.00	-	280.00
Total end 1995	2 481.76	404.92	6.20	-	2 892.88	914.50	3 807.38

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ALBERTA							
Total end 1985	5 915.80	524.10	44.87	-	6 484.77	733.70	7 218.47
Additions 1986	380.00	-	-	-	380.00	-	380.00
Total end 1986	6 295.80	524.10	44.87	-	6 864.77	733.70	7 598.47
Additions proposed							
1989	400.00	-	-	-	400.00	-	400.00
1990	380.00	-	-	-	380.00	-	380.00
1991	400.00	-	-	-	400.00	-	400.00
1994	375.00	-	-	-	375.00	-	375.00
1995	375.00	-	-	-	375.00	-	375.00
1996	-	200.00	-	-	200.00	-	200.00
1997	-	200.00	-	-	200.00	-	200.00
1998	375.00	-	-	-	375.00	-	375.00
1999	375.00	-	-	-	375.00	-	375.00
2000	375.00	100.00	-	-	475.00	-	475.00
2001	360.00	200.00	-	-	560.00	-	560.00
2002	-	200.00	-	-	200.00	-	200.00
2003	750.00	300.00	-	-	1 050.00	-	1 050.00
2004	375.00	-	-	-	375.00	-	375.00
2005	375.00	-	-	-	375.00	-	375.00
Total end 2005	11 210.80	1 724.10	44.87	-	12 979.77	733.70	13 713.47
BRITISH COLUMBIA							
Total end 1985	1 351.67	153.70	93.52	-	1 598.89	10 843.67	12 442.56
Additions 1986	-	-	-	-	.00	-	.00
Total end 1986	1 351.67	153.70	93.52	-	1 598.89	10 843.67	12 442.56
Additions proposed							
1997	-	-	-	-	.00	160.00	160.00
1998	-	-	-	-	.00	80.00	80.00
2000	-	-	-	-	.00	300.00	300.00
2001	-	-	-	-	.00	600.00	600.00
2002	-	-	-	-	.00	110.00	110.00
2003	-	-	-	-	.00	110.00	110.00
2004	-	-	-	-	.00	55.00	55.00
Total end 2004	1 351.67	153.70	93.52	-	1 598.89	12 258.67	13 857.56
YUKON and N.W.T.							
Total end 1985	-	-	181.84	-	181.84	130.70	312.54
Additions 1986	-	-	-	-	.00	-	.00
Total end 1986	-	-	181.84	-	181.84	130.70	312.54
Additions proposed							
1988	-	-	1.90	-	1.90	-	1.90
1991	-	-	.54	-	.54	-	.54
1993	-	-	2.50	-	2.50	-	2.50
Total end 1993	-	-	186.78	-	186.78	130.70	317.48

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total End 1985	27 393.85	2 276.59	575.30	9 455.00	39 700.74	55 879.36	95 580.10
Additions 1986	380.00	50.00	.00	1 529.00	1 959.00	969.01	2 928.01
Total End 1986	27 773.85	2 326.59	575.30	10 984.00	41 659.74	56 848.37	98 508.11
Additions Proposed							
1987	.00	104.00	.00	830.00	934.00	.00	934.00
1988	.00	100.00	1.90	881.00	982.90	.00	982.90
1989	400.00	100.00	.00	881.00	1 381.00	1 023.00	2 404.00
1990	380.00	.00	.00	.00	380.00	256.00	636.00
1991	830.00	.00	.54	881.00	1 711.54	640.00	2 351.54
1992	.00	.00	.00	881.00	881.00	1 334.00	2 215.00
1993	335.00	.00	2.50	.00	337.50	950.00	1 287.50
1994	525.00	.00	.00	.00	525.00	85.00	610.00
1995	955.00	500.00	.00	.00	1 455.00	918.00	2 373.00
1996	.00	200.00	.00	.00	200.00	1 033.00	1 233.00
1997	.00	200.00	.00	.00	200.00	1 447.00	1 647.00
1998	710.00	200.00	.00	.00	910.00	1 613.00	2 523.00
1999	375.00	.00	.00	.00	375.00	1 837.00	2 212.00
2000	675.00	100.00	.00	.00	775.00	2 004.00	2 779.00
2001	360.00	200.00	.00	.00	560.00	812.00	1 372.00
2002	.00	500.00	.00	.00	500.00	431.00	931.00
2003	1 050.00	600.00	.00	.00	1 650.00	110.00	1 760.00
2004	375.00	.00	.00	.00	375.00	55.00	430.00
2005	375.00	.00	.00	.00	375.00	.00	375.00
2006	300.00	.00	.00	.00	300.00	.00	300.00
Total End 2006	35 418.85	5 130.59	580.24	15 338.00	56 467.68	71 396.37	127 864.05

Source: Energy, Mines and Resources Canada.

Table A8. Installed generating capacity expansion in Canada by station. Major 1986 additions and 1987 - 2006 projections

Province and Station	Type*	Additions in 1986	Scheduled Completion Date	Additions Proposed	Status*	Proposed Plant Capacity
		(MW)		(MW)		(MW)
NOVA SCOTIA						
New Thermal	S(c)		1994	150	P	
			1995	300	P	
			2000	300	P	
			2003	300	P	
			2006	300	P	1 350.00
Trenton	S(c)		1991	150	P	360.00
NEW BRUNSWICK						
New Steam	S(c)		1993	335	P	
			1998	335	P	670.00
QUEBEC						
LG-4		3 × 294.5			I**	2 650.50
Manic 5A	H		1989	4 × 245	P	2 272.00
LG-2A	H		1992	2 × 317	P	
			1992	316	P	
			1993	316	P	
			1993	2 × 317	P	7 228.00
LG-1	H		1995	6 × 108	P	
			1996	6 × 108	P	1 296.00
LA-1 (Laforge)	H		1997	3 × 130	P	
			1997	3 × 131	P	783.00
Brisay	H		1996	193	P	
			1996	192	P	385.00
Sainte-Marguerite	H		1998	2 × 411	P	822.00
Grande-Baleine	H		1999	395	P	
			1999	2 × 396	P	
			2000	304	P	
			2000	2 × 700	P	2 891.00
Ashupmushuan	H		2001	2 × 106	P	
			2002	3 × 107	P	533.00
Peak Hydro	H		1995	270	P	
			1997	374	P	
			1998	191	P	835.00
Peak Gas	GT(O)		1995	500	P	
			1998	200	P	
			2002	300	P	
			2003	300	P	1 300.00

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Table A8. Installed generating capacity expansion in Canada by station. Major 1986 additions and 1987 - 2006 projections (Continued)

Province and Station	Type*	Additions in 1986	Scheduled Completion Date	Additions Proposed	Status*	Proposed Plant Capacity
		(MW)		(MW)		(MW)
ONTARIO						
Bruce B	N	830			I	
			1987	830	C	3 320.00
Darlington	N		1988	881	C	
			1989	881	C	
			1991	881	C	
			1992	881	C	
	GT		1987	4 × 26	P	3 628.00
Magpie	H		1989	4 × 7.5	P	
			1989	2 × 6.5	P	43.00
Pickering B	N	516			I	2 064.00
MANITOBA						
Limestone	H		1990	2 × 128	C	
			1991	5 × 128	C	
			1992	3 × 128	C	1 280.00
Wuskwatim	H		2009	87.5	P	
			2010	3 × 87.5	P	350.00
Conawapa	H		1997	130	P	
			1998	4 × 130	P	
			1999	5 × 130	P	1 300.00
SASKATCHEWAN						
Nipawin	H	85			I	255.00
Meadow Lake	GT(G)	50				101.00
Ermine	GT(G)		1988	100	P	100.00
Saskatoon	GT(G)		1989	100	P	100.00
Shand	S(c)		1991	280		
			1995	280		560.00
Island Falls	H		1994	85		190.00

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Table A8. Installed generating capacity expansion in Canada by station. Major 1986 additions and 1987 - 2006 projections (Continued)

Province and Station	Type*	Additions in 1986	Scheduled Completion Date	Additions Proposed	Status*	Proposed Plant Capacity
		(MW)		(MW)		(MW)
ALBERTA						
Genesee	S(c)		1989	400	C	
			1991	400	C	800.00
Sheerness	S(c)			380	I	
			1990	380	C	760.00
New Steam	S(c)		1994	375	P	
			1995	375	P	
			1998	375	P	
			1999	375	P	
			2000	375	P	
			2003	2 × 375	P	
			2004	375	P	
			2005	375	P	3 375.00
Peak Gas	GT		1996	2 × 100	P	
			1997	2 × 100	P	
			2000	1 × 100	P	
			2001	2 × 100	P	
			2002	2 × 100	P	
			2003	3 × 100	P	1 200.00
BRITISH COLUMBIA						
Keenleyside	H		1997	2 × 80	P	
			1998	1 × 80	P	240.00
Murphy Creek	H		2002	2 × 55	P	
			2003	2 × 55	P	275.00
			2004	55	P	
Peace Site C	H		2000	2 × 150	P	
			2001	4 × 150	P	900.00
YUKON						
Dawson	IC		1988	.9	P	
			1993	.9	P	4.32
NORTHWEST TERRITORIES						
Hay River	IC		1986	3	P	12.00

*** Legend**

H	*Hydro*	*IC*	*Internal combustion*
S(c)	*Steam (coal)*	*GT*	*Gas turbine*
N	*Nuclear*	*I*	*Installed*
P	*Planned*	*C*	*Under construction*
GT(o)	*Gas turbine (oil)*	*I***	*Installed but testing*

GT (G) Gas Turbine (natural gas)

Source: Energy, Mines and Resources Canada.

Definitions and Abbreviations

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 MW, or might sell 50 MW of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 MW.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity, which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt hour (kW.h).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity, which is based on the amount of energy taken (e.g. 20 mills per kW.h). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Power: Electric power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts; one million kilowatts. (See Watt.).

Gigawatt hour (GW.h): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy: Energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h): A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil, or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: first, in case of unexpected breakdown of generating equipment; second, in case the actual peak load is higher than forecast.

Terawatt Hours (TW.h): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

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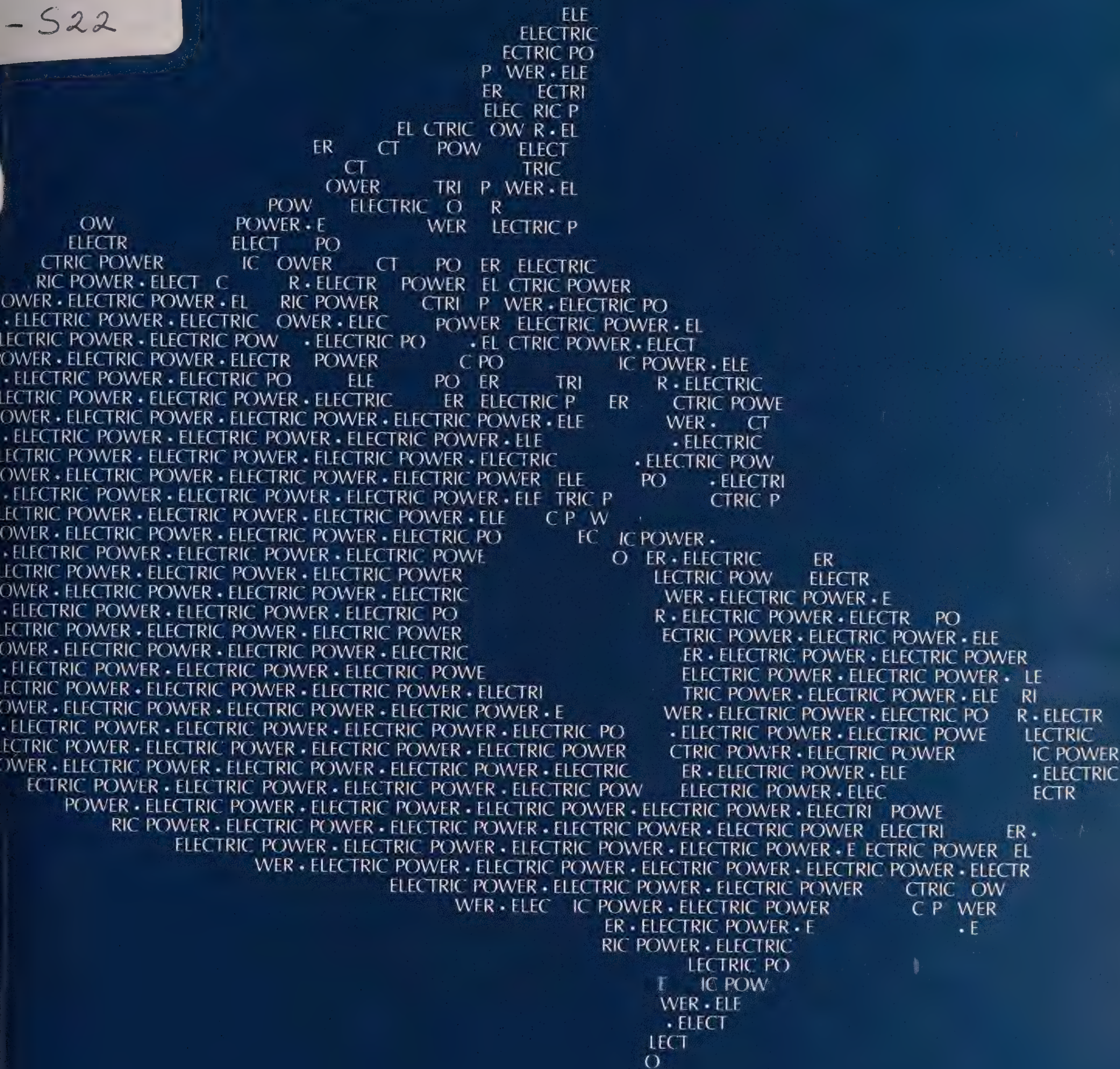

ELECTRIC POWER IN CANADA 1987

THE ENERGY OF OUR RESOURCES

THE POWER OF OUR IDEAS

Canada

Electric Power in Canada 1987

Electrical Energy Branch
Energy Commodities Sector
Energy, Mines and Resources Canada

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Mactaquac is the largest hydroelectric generating station in the Maritime provinces, with a capacity of 653 MW. It is owned by N.B. Power and is located on the Saint John River near Fredericton.

1. The Electric Power Industry in Canada

INDUSTRY STRUCTURE

Under the Canadian Constitution, electricity is primarily within the jurisdiction of the provinces. As a consequence, Canada's electrical industry is organized along provincial lines. In most provinces, the industry is highly integrated, with the bulk of the generation, transmission, and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1.

Among the major electric utilities, eight are provincially owned, four are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1987, provincial electric utilities owned about 85.2 per cent of total installed generating capacity and produced about 83.5 per cent of total generated electricity. The four investor-owned utilities accounted for 5.8 per cent of all Canadian electric utility capacity and produced about 6.9 per cent of total electricity. Municipally owned utilities accounted for 1.2 per cent of capacity ownership, and produced 0.3 per cent of total generated electricity; two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These industries are concentrated in the pulp and paper, mining, and aluminum smelting sectors. In 1987, industrial establishments owned about 6.1 per cent of total capacity and produced about 7.1 per cent of total generated electricity in Canada, as shown in Table 1.2.

Table 1.1. Canada's major electric utilities by province

Province	Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Co. Ltd.	Private
Prince Edward Island	Maritime Electric Co. Ltd.	Private
Nova Scotia	Nova Scotia Power Corporation	Provincial
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Ltd.	Private
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Private
British Columbia	British Columbia Hydro and Power Authority	Provincial
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Energy, Mines and Resources Canada.

In addition to the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, 87 per cent of which are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1987, the small utilities accounted for 1.4 per cent of total Canadian capacity and produced 1.5 per cent of electrical energy.

ELECTRICITY AND THE ECONOMY

The electric power industry is a significant presence within the Canadian economy. As indicated in Table 1.3, there were about 91 000 people directly employed by the industry in 1986, about 1.0 per cent of total Canadian employment. Total revenue increased to about \$17.4 billion in 1986 from \$16.8 billion in 1985, an increase of 3.6 per cent. Of this total, approximately \$1.1 billion or 6.3 per cent came from export earnings. The electric power industry has steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, and 3.7 per cent in 1986.

Total assets of the industry were about \$94.7 billion in 1986, accounting for about 7 per cent of the capital stock of the economy. This reflects the capital-intensive nature of the electric power industry. Ontario Hydro, HydroQuébec, and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked first, second, and fifth respectively among all Canadian companies.

Table 1.2. Electrical capacity and production by utilities and industrial establishments, 1930-1987

	Installed Generating Capacity		Energy Production	
Year	Utilities	Industrial Establishments	Utilities	Industrial Establishments
	(per cent)			
1930	83	17	93	7
1940	84	16	91	9
1950	83	17	88	12
1960	80	20	78	22
1965	82	18	77	23
1970	88	12	84	16
1975	90	10	87	13
1980	92	8	89	11
1981	92	8	90	10
1982	93	7	90	10
1983	93	7	90	10
1984	93	7	91	9
1985	93	7	92	8
1986	94	6	92	8
1987	94	6	91	8

Source: Electric Power Statistics, Volume II, *Statistics Canada, 57-202, 57-001.*

CANADIAN ELECTRIC UTILITIES

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC and NLH serve about 200 000 customers.

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited, and Union Electric Light and Power Company. Approximately 89 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations.

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation (LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant,

ıe of the largest power facilities the world. NLH's on-island ıpacity is generated from oil and ydro sources.

rince Edward Island

laritime Electric Company imited (MECL) is an investor-wned utility which has provided lectricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission, and distribution of electricity throughout the island. MECL operates two oil-fired generating plants on the island, and it has a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B. It leases from the P.E.I. government the submarine cable interconnection that connects the island to New Brunswick. MECL is the major distributor on the island, serving about 46 200 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

able 1.3. Electric utility assets, revenue and employees, 1986

tility	Assets	Revenue	Employees
	($ millions)		(persons)
lajor utilities			
Newfoundland and Labrador Hydro	2 095	321	1 333
Newfoundland Light & Power Co. Ltd.	367	245	905
Maritime Electric Co. Ltd.	91	54	203
Nova Scotia Power Corporation	1 475	476	2 383
New Brunswick Electric Power Commission	2 830	825	2 521
Hydro-Québec	30 588	4 734	20 796
Ontario Hydro	31 357	4 853	32 045
The Manitoba Hydro-Electric Board	3 240	570	4 142
City of Winnipeg Hydro-Electric System	111	84	643
*Saskatchewan Power Corporation**	2 857	847	3 181
TransAlta Utilities	3 700	916	2 527
Edmonton Power	954	271	846
Alberta Power Ltd.	1 338	375	1 371
*B.C. Hydro and Power Authority**	9 802	1 987	6 393
Northern Canada Power Commission	143	99	322
All minor utilities	375	700	11 547
Canada	94 698	17 357	91 158

* *Includes natural gas operations.*

Source: Electric utilities' annual reports.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. It is a provincial Crown corporation that produces and distributes electricity throughout the province. NSPC generates most of its electricity from thermal energy, with more than half of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. NSPC has two subsidiaries: Nova Scotia Light and Power Co. Ltd., and Eastern Light and Power Co. Ltd. In 1987, NSPC served about 350 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (N.B. Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of N.B. Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 14 generating stations, and electricity is generated from a balance of nuclear, hydro, and thermal sources. N.B. Power also purchases energy from Quebec. In 1987, N.B. Power directly provided electricity to 253 000 customers and indirectly served an additional 39 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in 1944. It is responsible for the generation, transmission, and distribution of most of the electricity sold in Quebec. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves more than 2.9 million customers.

Hydro-Québec has five wholly owned subsidiaries: the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex; Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; Cedars Rapids Transmission Company Limited, which transmits export power to New York State; Somarex Inc., which will finance, construct, and operate a transmission line in the State of Maine; and Nouveler Inc., which promotes energy efficiency and alternative energy sources. Hydro-Québec is also a shareholder in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by the provincial legislature. It has broad powers to produce, buy, and deliver electric power throughout the province and currently operates under the Power Corporation Act. The main responsibility of Ontario Hydro is to provide power to the province's 316 municipal utilities, which in turn distribute power to their own customers. In 1987, more than 3.2 million customers were served by Ontario Hydro and the municipal utilities in the province. In addition, Ontario Hydro supplies about 100 major industrial users directly and about 780 000 rural retail customers in areas or communities not served by municipal utilities. Electricity generated by Ontario Hydro is from a balance of thermal, nuclear, and hydro sources.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and the surrounding area. Great Lakes Power operates nine generating stations primarily located on two river systems flowing into the eastern end of Lake Superior, and is now developing additional capacity on the Magpie River. In 1987, the utility served almost 10 000 customers in Northern Ontario.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1987, Manitoba Hydro served about 360 000 customers directly, and Winnipeg Hydro served about 113 000 customers.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission, and distribution of natural gas and electricity. At the end of 1987, the corporation served more than 402 000 customers with electricity and 280 000 customers with natural gas. (In May 1988, the provincial government announced

; intention to separate the ectricity and gas operations of ıskPower into separate Crown ›rporations.) The bulk of the ectricity produced by SaskPower from thermal sources.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 91 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 9 per cent of Alberta's electrical

Ontario Hydro technicians lower a pendulum to measure structural changes within the body of the McConnell Lake control dam. Ontario Hydro's dam safety program carefully monitors structures to ensure that changes resulting from fluctuating temperatures and water levels are within acceptable limits.

energy is supplied by industry. Almost 92 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 71 per cent of the electric energy requirements of Alberta are supplied by the company, to over half of the population. In 1987, about 290 000 customers were served directly by TransAlta, while another 300 000 customers were served indirectly through wholesale contracts. TransAlta Utilities has four subsidiaries: TransAlta Resources Corporation; TransAlta Fly Ash Ltd.; Kanelk Transmission Co. Ltd.; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in Alberta, and a subsidiary of Canadian Utilities Ltd. The activity of the company is concentrated in east-central and northern Alberta. Alberta Power supplied about 19 per cent of the total Alberta electricity requirements in 1987, serving about 150 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. Although the utility produced only 1.4 per cent of the electricity requirements of Alberta, it had a 15 per cent share of the total provincial market in 1987, serving more than 234 000 customers. Edmonton Power purchases most of its electricity from TransAlta Utilities and Alberta Power.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro), incorporated in 1961, is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior, which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada and the largest distributor of natural gas in British Columbia. B.C. Hydro generates, transmits, and distributes electricity to more than one million customers in a service area which contains more than 90 per cent of the population of the province. B.C. Hydro also distributes natural gas and operates a provincial railway. Both of these responsibilities, as well as B.C. Hydro's research operations, are being privatized by the provincial government.

West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 60 000 customers in its service area. The company also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. In 1987, West Kootenay Power marked its ninetieth year of operation and, with the purchase of the company's shares by UtiliCorp United Inc. of Missouri, the end of a 71-year association with Cominco Ltd. The purchase was concluded in September 1987, following a review by the British Columbia Utilities Commission.

Yukon and Northwest Territories

From 1956 to 1987, the Northern Canada Power Commission (NCPC) was the principal agency generating and transmitting electrical energy in the Yukon and the Northwest Territories. By 1987, the NCPC was operating 50 separate power systems throughout the territories, serving approximately 15 000 customers. Electricity in the North is generated from a balance of hydro sources and diesel fuel.

In March 1987, the Government of the Yukon Territory and the federal government reached an agreement to transfer the Yukon portion of the NCPC from federal to territorial control and ownership. The Yukon government has placed ownership and control of the new company, the Yukon Energy Corporation, with the Yukon Development Corporation. The latter corporation was established under the Yukon Development Corporation Act in 1986. The Yukon Energy Corporation has entered into a management contract with the Yukon Electrical Co. Ltd., an existing Yukon electrical utility and a subsidiary of Alberta Power Limited, to operate the assets of the new utility, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Yukon Energy Corporation has assets worth $95 million.

In May 1988, the federal government reached a similar agreement with the Government of the Northwest Territories, transferring the N.W.T. portion of NCPC assets, worth $96 million, from federal to territorial control. Under the terms of the agreement, the territorial government assumes all responsibility for the utility, including rate-setting. A new territorial Crown corporation, the Northwest Territories Power Corporation, has been established to assume these responsibilities.

Newfoundland Light & Power Company employees carry out work at a substation. NLPC is continually upgrading its facilities to meet increased power needs in rural Newfoundland.

2. Canadian Electricity in the International Context

This chapter compares Canada's electricity supply and demand with those of selected other countries. All data used in this chapter were obtained from the United Nations' *Energy Statistics Yearbook*, with the exception of data on electricity prices, which were obtained from the *Quarterly Energy Review*, published by the Economist Intelligence Unit.[1]

INSTALLED GENERATING CAPACITY

At the end of 1985, total world electrical generating capacity was approximately 2418 GW. A breakdown of capacity by fuel type for the top 20 countries is shown in Table 2.1. Of the world total, conventional thermal accounted for 1608 GW (66.5 per cent); hydro 555 GW (22.9 per cent); nuclear 251 GW (10.4 per cent); and geothermal 4 GW (0.2 per cent).

The U.S. electric power industry was the largest in the world with a total generating capacity of 702 GW, accounting for 29 per cent of the total. The U.S.S.R. was second, with generating capacity of 319 GW; and Japan was third with 170 GW. The United States leads in installed capacity for every fuel type. U.S. conventional thermal accounted for more than 33 per cent of the world's thermal capacity; hydro for 15 per cent; nuclear for 33 per cent; and geothermal for 40 per cent.

Canada ranked fourth in the world with a generating capacity of about 99 GW, accounting for 4 per cent of the world total. In terms of fuel type, Canada's hydro capacity is the third largest in the world, next to the U.S. and U.S.S.R.; Canada's nuclear capacity is sixth in the

Table 2.1. International comparison of installed generating capacity, 1985

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
			(MW)		
United States	533 611	84 986	81 566	1 712	701 875
U.S.S.R.	229 936	61 257	28 100	0	319 293
Japan	110 291	34 337	24 686	214	169 528
Canada	30 937	57 458	10 889	0	99 284
West Germany	69 938	6 668	16 095	3	92 704
France	29 500	21 800	37 500	0	88 800
China	55 700	26 500	0	0	82 200
United Kingdom	56 352	4 190	7 064	1	67 607
Italy	36 098	17 166	1 273	439	54 976
India	34 969	15 115	1 096	0	51 180
Brazil	6 266	36 881	657	0	43 804
Spain	19 600	13 790	5 815	0	39 205
Sweden	8 018	15 690	9 455	5	33 168
Australia	24 570	6 557	0	0	31 127
Poland	27 063	1 975	0	0	29 038
South Africa	23 190	572	965	0	24 727
Mexico	17 059	6 601	0	425	24 085
Norway	245	22 991	0	0	23 236
East Germany	18 269	1 845	1 830	0	21 944
Czechoslovakia	14 632	2 875	2 040	0	19 547
World Total	1 607 712	555 463	250 697	4 242	2 418 114
	(66.5%)	(22.9%)	(10.4%)	(0.2%)	(100%)

Source: Energy Statistics Yearbook, 1985, *United Nations, pp.324-351.*

[1] The 1986 edition of *Electric Power in Canada* compared installed generating capacity and electricity generation by fuel type among a number of countries for the year 1985. The data used in the comparison were obtained from various sources. This year, in order to obtain a consistency in the data and to permit an accurate comparison in the areas of installed generating capacity, energy generation, per capita consumption, demand growth, rates, and electricity trade, only United Nations' data have been used. Unfortunately, the most recent data available from the U.N. at this time are for 1985.

vorld, and its conventional thermal capacity is ninth.

ELECTRICITY GENERATION

During 1985, a total of 9675 TW.h of electricity was generated around the world. Of this total, conventional thermal, mainly from coal-fired stations, accounted for 6199 TW.h (64.1 per cent); hydro 1995 TW.h (20.6 per cent); nuclear 1453 TW.h (15 per cent); and geothermal 28 TW.h (0.3 per cent). Although nuclear accounted for only 10 per cent of the world total generating capacity in 1985, its energy production share was 15 per cent, indicating that most nuclear stations were operating at a relatively high capacity factor compared with conventional thermal stations and hydro plants. Generation by fuel type for the world's top 20 producers is shown in Table 2.2.

About 26 per cent of total world electricity generation took place in the United States in 1985. Its conventional thermal generation was 1848 TW.h, accounting for 30 per cent of the world conventional thermal total.

Canada was the largest hydroelectric energy producer in the world in 1985 with 304 TW.h, accounting for about 15 per cent of total hydro production. Canada's total production ranked fourth in the world (behind the United States, the U.S.S.R., and Japan), with total production of 460 TW.h, or 5 per cent of the world total.

The United States was the largest nuclear energy producer in the world in 1985, with a total of 384 TW.h or 27 per cent of the world nuclear total. As a proportion of total national electricity production, however, France's nuclear generation was the largest at about 65 per cent. Although Belgium was not among the top 20 electricity producers, its national nuclear proportion was the second largest at 61 per cent. Sweden ranked third at 43 per cent. Canada's nuclear share was a relatively small 13 per cent. The nuclear shares of the United States and the U.S.S.R. were 15 per cent and 11 per cent respectively.

DOMESTIC ELECTRICITY CONSUMPTION

In 1985, Norway consumed 24 777 kW.h of electricity per capita, more than any other country in the world. Canada was the third

Table 2.2. International comparison of electricity generation by fuel type, 1985

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
		(GW.h)			
United States	1 848 277	282 499	383 691	10 724	2 525 191
U.S.S.R.	1 168 000	206 000	170 000	0	1 544 000
Japan	424 427	87 947	159 578	1 460	673 412
Canada	95 045	304 302	61 061	0	460 408
China	318 300	92 400	0	0	410 700
West Germany	265 191	15 621	125 902	0	406 714
France	52 100	61 200	213 100	0	326 400
United Kingdom	229 533	4 095	61 094	0	294 722
Brazil	14 689	178 256	0	0	192 945
India	125 795	58 001	4 683	0	188 479
Italy	131 440	41 092	7 024	2 681	182 237
Poland	133 814	3 894	0	0	137 708
Sweden	6 740	71 166	58 637	0	136 543
Spain	66 117	31 408	28 035	0	125 560
South Africa	117 658	710	3 925	0	122 293
Australia	104 541	14 428	0	0	118 969
East Germany	99 337	1 758	12 739	0	113 834
Norway	339	102 851	0	0	103 190
Mexico	65 523	26 241	0	1 641	93 405
Czechoslovakia	64 499	4 349	11 779	0	80 627
World Total	6 198 662 (64.1%)	1 995 611 (20.6%)	1 453 181 (15.0%)	27 893 (0.3%)	9 675 347 (100%)

Source: Energy Statistics Yearbook, 1985, *United Nations, pp.380-407.*

largest per capita electricity user, at 16 522 kW.h. Table 2.3 reports electricity consumption per capita in 1985 for 25 countries. The first ten countries are listed according to their actual global rankings. The second group of countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true rankings in the world.

As Table 2.3 shows, per capita consumption varies significantly among countries. Norway consumed more than 12 times the world average; Canada, Iceland, and Sweden more than eight times; and the United States about five times. Nigeria's and India's per capita consumption levels were less than 13 per cent of the world average. Although China was the fifth largest electrical energy producer in the world, its per capita consumption was only 20 per cent of the world average.

Two principal factors contribute to Canada's large per capita consumption of electricity. Abundant water resources have permitted the development of economical hydroelectric power projects in various regions, making electrical energy relatively inexpensive and plentiful. This has led to relatively high electricity consumption among all energy users, and it has led many electricity-intensive industries to locate in Canada. As well, Canada's northerly location means a long and cold winter, resulting in much energy being used for space-heating purposes.

TOTAL ELECTRICITY CONSUMPTION GROWTH

World electricity consumption grew by approximately 4.5 per cent annually between 1983 and 1985. Table 2.4 reports total electricity consumption growth rates during the period 1983-85 for 25 selected countries around the world. In general, most of the countries with high consumption growth rates were developing countries. This was largely due to the fact that many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Canada was one of the few developed countries with a high electricity consumption growth rate during the period 1983-85. Its average growth rate was 5.7 per cent, compared with 5.0 per cent for France and Japan, 3.2 per cent for the United States and West Germany, 2.9 per cent for Italy, and 2.8 per cent for the United Kingdom. The world average during the same period was 4.5 per cent. The United Kingdom, Italy, and most of the African countries were among the countries with the lowest consumption growth rates in the world.

ELECTRICITY TRADE

In both North America and Europe, there are substantial interconnections between electricity generating stations. Interconnections improve the economics and security of

Table 2.3. International comparison of per capita electricity consumption, 1985

Country	kW.h/Person	As Percentage of World Average
Norway	24 777	1 241
Iceland	16 642	834
Canada	16 522	828
Sweden	16 165	810
Qatar	11 159	559
Luxembourg	11 088	556
United States	10 781	540
Finland	10 588	531
New Zealand	8 066	404
Australia	7 579	380
East Germany	6 799	341
West Germany	6 722	337
Japan	5 577	279
France	5 545	278
U.S.S.R.	5 445	273
United Kingdom	5 232	262
South Africa	3 294	165
Spain	3 230	162
Argentina	1 481	74
Brazil	1 444	72
Mexico	1 182	59
Egypt	495	25
China	396	20
India	248	12
Nigeria	93	5
World Average	1 996	100

Source: Energy Statistics Yearbook, 1985, *United Nations, pp.408-421.*

electricity supply, and they reduce the level of capacity needed to meet peak loads. Interconnections also improve the flexibility of electricity supply, making it possible to minimize costs by replacing the highest cost generation, such as oil-fired generation, with imported hydroelectric energy.

In 1985, a total of 216 TW.h of electricity was exported internationally, accounting for 2.2 per cent of world production. The world's largest electricity exporters and importers are reported in Tables 2.5 and 2.6 respectively.

As indicated in Table 2.5, Canada was the largest electricity exporter in the world in 1985 with a total of 43.4 TW.h, accounting for 20 per cent of total world exports. France was second, exporting 28.8 TW.h, and the U.S.S.R. was third with 27.3 TW.h.

On the import side, the United States was the largest importer in 1985 with a total of 45.9 TW.h, or about 21 per cent of total world imports. Italy was second with imports of 25.1 TW.h; and West Germany was third with 18.8 TW.h. Although the United States was the largest importer, its total imports accounted for only 1.8 per cent of its total consumption in 1985. Luxembourg was the country most heavily dependent on electricity trade; it exported about 84 per cent of its production, and imported 98 per cent of its consumption.

ELECTRICITY INTENSITIES

Table 2.7 compares the intensity of electricity use in the economies of all 24 member countries in the Organization for Economic Co-Operation and Development (OECD) for the period 1960-85. Electricity intensity is defined as total electricity consumption per dollar of Gross Domestic Product (GDP). To facilitate the comparison, all currencies were converted into U.S. dollars at 1980 prices and

Table 2.4. International comparison of total electricity consumption growth rates

Country	1983	1984	1985	Average 1983-85
		(per cent)		
Indonesia	35.5	37.8	1.6	25.0
Jordan	26.9	20.1	7.3	18.1
Iraq	18.2	14.0	1.6	11.3
Thailand	12.4	11.1	9.5	11.0
India	7.6	11.7	11.8	10.4
South Korea	12.5	18.6	-0.3	10.3
Sweden	10.7	8.7	9.2	9.5
Kuwait	6.8	10.7	10.5	9.3
Malaysia	11.0	8.1	8.5	9.2
Iran	14.5	12.6	0.4	9.2
Syria	10.1	9.5	6.1	8.6
Brazil	7.3	9.9	7.9	8.4
Singapore	10.1	8.5	5.3	8.0
China	7.3	7.4	9.0	7.9
Turkey	4.4	12.6	6.5	7.8
Norway	6.8	5.8	5.4	6.0
Canada	4.6	7.1	5.3	5.7
Japan	6.6	4.5	4.0	5.0
France	2.4	5.4	7.3	5.0
Australia	0.9	6.3	5.3	4.2
U.S.S.R.	3.7	5.2	3.3	4.1
United States	3.0	4.5	2.2	3.2
West Germany	2.8	3.8	3.1	3.2
Italy	1.1	4.8	2.7	2.9
United Kingdom	1.6	1.8	5.1	2.8
World Total	4.1	5.5	4.0	4.5

Source: Calculated from Energy Statistics Yearbook, 1985, *United Nations, pp.408-421.*

exchange rates. Because of the limited availability of data, only OECD countries are included in the table. Among these countries, Norway had the highest electricity intensity, followed by Canada, Iceland, New Zealand, and Sweden. All five countries had electricity-GDP ratios greater than one in 1985.

All 24 OECD member countries experienced a time-trend increase in electricity intensity between 1960 and 1985, although some minor fluctuations occurred in the United States, Japan, the United Kingdom, Norway, and Luxembourg. Among the seven most industrialized countries, France had the fastest growth in electricity intensity during the period 1960-85, with an average annual increase of 2.0 per cent. France was followed by West Germany with 1.9 per cent, Italy with 1.6 per cent, the United States with 1.5 per cent, Canada with 1.1 per cent, the United Kingdom with 1.0 per cent, and Japan with 0.7 per cent.

In the United States, electricity intensity growth reached a peak in 1980, and then declined slightly and stabilized at the 1975 level. In Japan, electricity intensity grew modestly between 1960 and 1975; however, since then it has gradually declined to its 1970 level. The United Kingdom's electricity intensity grew strongly, by about 3.2 per cent annually between 1960 and 1970. Since then, it has declined steadily by 0.5 per cent per year for the period 1970-85.

Table 2.5. International comparison of electricity exports, 1985

Country	Exports* (GW.h)	Production (GW.h)	Percentage of Exports to Production
Canada	43 416	440 408	9.4
France	28 800	326 400	8.8
U.S.S.R	27 246	1 544 000	1.8
Switzerland	23 210	53 872	43.1
West Germany	16 330	406 714	4.0
Austria	7 770	43 923	17.7
Poland	7 568	137 708	5.5
Czechoslovakia	7 257	80 627	9.0
Sweden	6 675	136 543	4.9
Belgium	5 543	56 356	9.8
Spain	5 001	125 560	4.0
United States	4 965	2 525 191	0.2
Norway	4 618	103 190	4.5
East Germany	3 674	113 834	3.2
Zambia	3 100	10 090	30.7
Denmark	2 695	29 064	9.3
Uruguay	2 678	6 602	40.6
Yugoslavia	2 036	73 942	2.8
Hungary	1 924	26 779	7.2
Bulgaria	1 655	41 633	4.0
Italy	1 436	182 237	0.8
Portugal	1 284	19 007	6.8
Romania	1 000	75 268	1.3
Finland	878	47 098	1.9
Laos	723	1 350	53.6
Luxembourg	422	502	84.1
Netherlands	126	62 936	0.2
World Total	216 071	9 675 347	2.2

** Includes non-cash exchanges.*

Source: Energy Statistics Yearbook, 1985, *United Nations, pp.408-421.*

Table 2.6. International comparison of electricity imports, 1985

Country	Imports* (GW.h)	Consumption (GW.h)	Percentage of Imports to Consumption
United States	45 901	2 566 127	1.8
Italy	25 105	205 906	12.2
West Germany	18 829	409 213	4.6
Switzerland	14 512	45 174	32.1
Hungary	12 732	37 587	33.9
Czechoslovakia	10 796	84 166	12.8
Austria	6 051	42 204	14.3
Bulgaria	5 959	45 937	13.0
Finland	5 565	51 785	10.8
Belgium	5 497	56 310	9.8
Poland	5 456	135 596	4.0
France	5 400	303 000	1.8
Sweden	5 142	135 010	3.8
Netherlands	4 626	67 436	6.9
Norway	4 055	102 627	4.0
Luxembourg	3 945	4 025	98.0
Spain	3 927	124 586	3.2
East Germany	3 836	113 996	3.4
Portugal	3 530	21 253	16.6
Denmark	3 155	29 524	10.7
Canada	3 093	420 085	0.7
Zimbabwe	3 000	7 342	40.9
Brazil	2 781	195 724	1.4
Yugoslavia	2 663	74 569	3.6
Turkey	2 137	35 450	6.0
China	1 050	411 750	0.3
World Total	216 071	9 675 347	2.2

* *Includes non-cash exchanges.*

Source: Energy Statistics Yearbook, 1985, *United Nations, pp.408-421.*

Table 2.7. International comparison of electricity consumption per unit of GDP

Country	1960	1965	1970	1975	1980	1985
			(kW.h/U.S. $1980)			
Norway	1.30	1.55	1.56	1.58	1.45	1.59
Canada	1.07	1.07	1.20	1.23	1.29	1.42
Iceland	0.48	0.44	0.84	0.97	0.98	1.07
New Zealand	0.51	0.63	0.73	0.87	0.98	1.03
Sweden	0.52	0.58	0.63	0.70	0.78	1.02
Finland	0.40	0.53	0.60	0.66	0.77	0.91
United States	0.60	0.65	0.80	0.88	0.89	0.87
Portugal	0.39	0.44	0.48	0.57	0.68	0.83
Luxembourg	0.64	1.06	0.78	0.97	0.87	0.80
Australia	0.37	0.46	0.51	0.58	0.66	0.74
Greece	0.19	0.25	0.39	0.50	0.58	0.69
Ireland	0.28	0.38	0.49	0.50	0.57	0.57
Spain	0.26	0.29	0.37	0.42	0.51	0.56
Japan	0.45	0.47	0.53	0.57	0.55	0.53
United Kingdom	0.41	0.50	0.56	0.55	0.53	0.52
Austria	0.42	0.44	0.46	0.47	0.49	0.52
Italy	0.34	0.39	0.42	0.46	0.48	0.51
West Germany	0.31	0.35	0.40	0.45	0.46	0.49
Turkey	0.15	0.20	0.26	0.32	0.43	0.48
Belgium	0.29	0.32	0.36	0.40	0.43	0.47
France	0.27	0.29	0.32	0.34	0.40	0.44
Switzerland	0.31	0.31	0.32	0.37	0.38	0.42
Denmark	0.15	0.21	0.30	0.33	0.39	0.41
Netherlands	0.21	0.26	0.32	0.36	0.38	0.39

Source: Real Gross Domestic Product in U.S. dollars was obtained from National Accounts, 1960-1985, *Department of Economics and Statistics, OECD, February 1987. Electrical energy data were obtained from* Energy Statistics Yearbook, *United Nations, various issues.*

ELECTRICITY PRICES

A comparison of international electricity prices is difficult because of different rate schedules and national currencies. Nevertheless, a reasonable comparison has been established by using average revenue per kilowatt hour in a given sector and converting to a common national currency.

Tables 2.8 and 2.9 summarize electricity prices for the industrial and residential sectors respectively. Due to the limited data available, only 17 countries are reported in the tables. Canada's electricity prices are highly competitive relative to the other countries. In the industrial sector in 1985, Norway had the lowest electricity price with 1.42 U.S. cents/kW.h, followed by Canada with 2.88 U.S. cents/kW.h, and Sweden with 2.91 U.S. cents/kW.h. In the residential sector, Canada had the lowest price with 3.61 U.S. cents/kW.h. Norway was second with 3.93 U.S. cents/kWh, and Sweden was third with 3.98 U.S. cents/kW.h.

In both sectors, Japan had the highest electricity prices compared with 16 other member countries in the OECD. Its electricity prices were about 3.2 and 3.4 times the respective industrial and residential prices of Canada in 1985.

Table 2.8. International comparison of electricity prices in the industrial sector, 1985

Country	Industrial Prices (U.S. cents/kW.h)	As Percentage of Canada's Price
Norway	1.42	49
Canada	2.88	100
Sweden	2.91	101
Australia	3.14	109
France	3.66	127
Finland	4.05	141
Netherlands	4.16	144
Belgium	4.29	149
Denmark	4.50	156
Spain	4.63	161
West Germany	4.72	164
Switzerland	4.84	168
United Kingdom	4.86	169
United States	5.16	179
Portugal	5.66	197
Italy	5.97	207
Japan	9.22	320

Source: Electricity prices in national currency units were obtained from Quarterly Energy Review, *Western Europe and Far East Asia, various issues in 1986 and 1987, the Economist Intelligence Unit. Exchange rates expressed in national currency units per 1985 U.S. dollars were obtained from* National Accounts, 1960-1985, *OECD, February 1987.*

Table 2.9. International comparison of electricity prices in the residential sector, 1985

Country	Residential prices (U.S. cents/kW.h)	As percentage of Canada's price
Canada	3.61	100
Norway	3.93	109
Sweden	3.98	110
Australia	5.17	143
Finland	5.24	145
Switzerland	5.94	165
United Kingdom	6.74	187
Portugal	7.52	208
Italy	7.70	213
United States	7.79	216
West Germany	8.29	230
Denmark	8.48	235
France	8.51	236
Spain	8.58	238
Netherlands	8.73	242
Belgium	10.14	281
Japan	12.16	337

Source: Electricity prices in national currency units were obtained from Quarterly Energy Review, *Western Europe and Far East Asia, various issues in 1986 and 1987, the Economist Intelligence Unit. Exchange rates expressed in national currency units per 1985 U.S. dollars were obtained from* National Accounts, 1960-1985, *OECD, February 1987.*

3. The Regulatory Structure

FEDERAL REGULATION

Constitutional Authority

Under the Canadian Constitution, legislative authority for electricity generation, transmission, and distribution rests primarily with the provinces. Federal authority regarding electricity is restricted to nuclear energy and international and interprovincial trade. Federal responsibility for electricity trade stems primarily from Section 91.2 of the Constitution Act, which gives the federal government broad authority over trade and commerce. Federal control of nuclear energy derives from sections 91.29 and 92.10 of the Act, which permits federal regulation of matters that are declared by Parliament to be for the general advantage of Canada.

Provincial ownership of most energy resources stems from Section 109 of the Constitution Act which, in turn, is supplemented by Section 92A of the Act, giving provincial legislatures authority over the development, conservation, and management of sites and facilities in the province for the generation and production of electrical energy. Under Section 92A, which was enacted in 1982, the provinces also have authority to make laws regarding interprovincial sales of electricity, as long as such laws do not conflict with federal laws and do not permit discrimination in prices or supplies exported to different parts of Canada.

National Energy Board[1]

The National Energy Board (NEB) is a federal tribunal, created in 1959 by an Act of Parliament. The Board's powers and duties are derived from the National Energy Board Act. Under the Act, the Board advises the federal government on the development and use of energy resources and regulates specific matters concerning oil, gas, and electricity. The Board's jurisdiction over electrical matters is limited to the certification of international and designated interprovincial power lines and the licensing of electricity exports from Canada. The Board has no jurisdiction over imports of electricity.

Part III of the NEB Act provides for the federal regulation of international power lines. When reviewing an application for an international power line, the Board determines whether the line is in the public interest by assessing i) the availability of electricity for export, ii) the existence of markets, iii) economic feasibility, iv) financing considerations and Canadian participation, and v) any other consideration that may be relevant. In making this determination, the Board holds public hearings. Applications accepted by the Board are subject to review by the Governor in Council. The Board may authorize, without a public hearing, the construction and operation of international power lines not exceeding 50 kV.

The Governor in Council may by order designate a particular interprovincial power line to be regulated in the same manner as international power lines. When power from one province simply enters the grid of another province, there is no federal regulation.

Part VI of the NEB Act provides for the regulation of electric power exports. The Board issues export licences in which it imposes terms and conditions on the licensees. The Act restricts the duration of licences to 25 years. In considering an export application, the Board is required to take into account all factors pertaining to the public interest. In particular, the Board must satisfy itself that i) the quantity of electricity to be exported is surplus to reasonably foreseeable domestic requirements, and ii) the price is just and reasonable.

In interpreting the latter requirement the Board has established three guidelines concerning the export price: i) it must recover its appropriate share of the costs incurred in Canada; ii) it must not be less than the price to Canadians for equivalent service in related areas; and iii) it must not be materially less than the least-cost alternative available to the foreign purchaser at the same location in the country of export. Under the Free Trade Agreement, which is expected to come into force on January 1, 1989, the third price guideline will be eliminated.

Before licensing exports, the Board normally conducts a public hearing. However, when the export quantities are small (i.e., not more than 60 MW and 400 GW.h year), or when emergency conditions exist, the Board may issue "orders," authorizing exports without a public hearing.

Atomic Energy Control Board

Immediately after World War II, Canada began to study the question of how to encourage the use of nuclear energy for peaceful purposes while at the same time preventing its use for weapons. In 1946, Parliament passed the Atomic Energy Control Act with these objectives in mind.

The Act gave the federal government control over the development, application, and use of nuclear energy and established the Atomic Energy Control Board (AECB). The five-person AECB administers and enforces the Act, and licenses uses of radioactive materials and activities involving nuclear energy. It also regulates

[1] A new electricity export policy is to be announced in September 1988.

he health, safety, security, and environmental aspects of nuclear energy. The AECB reports to Parliament through the Minister of Energy, Mines and Resources.

The Board's primary function is to license Canadian nuclear facilities and activities dealing with prescribed substances and equipment. Nuclear facilities include power and research reactors, uranium mines and refineries, fuel fabrication plants, heavy water plants, waste management facilities, and particle accelerators. Prescribed substances include uranium, thorium, heavy water, and radioisotopes. Activities relating to such substances, which may be licensed, include production, processing, sale, use, import, and export. Before issuing a licence, the Board ensures that the appropriate health, safety and security standards are met.

The AECB's control also extends to international security of nuclear materials and technology. Through the licensing process, it ensures that nuclear equipment and supplies are exported in accordance with Canada's obligations under the Treaty on the Non-Proliferation of Nuclear Weapons.

PROVINCIAL REGULATION

As noted above, under the Canadian Constitution the provinces have legislative authority over the generation, transmission, and distribution of electricity. In most provinces some form of regulation exists, and most provinces have established regulatory bodies to oversee the utilities, although the degree of supervision varies. The major areas subject to review are rate-setting and the construction of new facilities. The nature of provincial regulation with respect to these matters is described briefly below. The environmental regulations of the provinces are described in chapter 11.

Newfoundland

Newfoundland Light & Power Company (NLPC) and Newfoundland and Labrador Hydro (NLH) are regulated by the Newfoundland Board of Commissioners of Public Utilities. The Board fully regulates the rates and policies of NLPC, including the construction of new facilities. Since 1977, the Board has also had authority under the Electric Power Control Act to review NLH's rates for residential customers. The Board makes recommendations to the Newfoundland Cabinet, which is the final authority for utility rates.

Cabinet is also the final authority with respect to NLH's capital expenditure program. Proposals by NLH for new facilities must receive Cabinet approval before construction can begin. NLPC must receive the approval of the province's Board of Commissioners of Public Utilities before proceeding with the construction of new facilities.

Prince Edward Island

Maritime Electric Company Limited is regulated by the Public Utilities Commission of Prince Edward Island under the provisions of the Electric Power and Telephone Act. The Commission has decision-making authority over electric utility rates in the province and screens all proposals for the construction of new generation and transmission facilities. If the Commission believes that a new facility may adversely affect the environment, a formal environmental assessment review process is initiated. A description of this process is provided in chapter 11.

Nova Scotia

Since 1976, the Nova Scotia Board of Commissioners of Public Utilities, in accordance with the provincial Public Utilities Act, has had full decision-making power over the utility's rates and policies.

The Board's authority extends to the construction of new facilities, and utilities are required to apply directly to the Board when planning new generation or transmission facilities. As part of the review process, the Board holds public hearings, during which the utility presents its proposed project, costs, and alternative plans. Members of the public may intervene directly during a hearing. The Board of Commissioners is the final authority on new facilities.

New Brunswick

As a Crown corporation, New Brunswick Power reports to the provincial government through its chairman, who is a member of the Cabinet. Rates and operations are regulated by a nine-member Board of Commissioners appointed by the Lieutenant Governor of New Brunswick. The utility's chairman and vice chairman sit on the Board. The Board's recommendations are referred to the provincial Cabinet, which is the final regulatory authority. A bi-partisan Crown corporation committee also reviews utility rates and operations annually.

N.B. Power must receive approval from the Lieutenant Governor-in-Council before proceeding with the construction of new facilities. Although the Lieutenant Governor-in-Council is the final authority in this regard, its decision is based upon a recommendation from the Minister of Municipal Affairs and Environment, following an evaluation of the project's possible environmental impacts. New Brunswick's environmental impact assessment process is described in chapter 11.

Quebec

In Quebec, a committee of the National Assembly on labour and the economy reviews Hydro-Québec's long-term development plan, which includes any proposed rate changes. The committee then makes a recommendation to the Minister of Energy and Resources, who in turn makes a recommendation to Cabinet. Rate increases can therefore be implemented by Hydro-Québec only after they have been approved by Cabinet.

The construction of new facilities by Hydro-Québec can take place only after the utility has received an Order-in-Council from the provincial government. Before an Order is issued, the Department of the Environment and the Department of Energy and Resources must approve plans for the new facility. Other departments and agencies are also consulted.

Ontario

Ontario Hydro is a provincially owned corporation which reports to the government through the Minister of Energy. The management of Ontario Hydro is under the direction and control of its Board of Directors. Proposed rate changes are referred to the Ontario Energy Board (OEB), through the Minister of Energy, for examination at public hearings. However, it is the Board of Ontario Hydro that is authorized to set the utility's rates, and it may accept or reject the recommendations of the OEB.

On matters concerning its generation expansion program and transmission facilities, Ontario Hydro is regulated by the provincial Joint Hearing Board. The Board is composed of members from the Environmental Assessment Board and the Ontario Municipal Board. The Joint Board makes a recommendation to the provincial government, and final approval must be given through an Order-in Council.

Manitoba

Under the Manitoba Public Utilities Board Act, Manitoba Hydro's rates may be reviewed by the Manitoba Public Utilities Commission in response to a directive from the government or an application from one of Hydro's clients. The Public Utilities Board reports its recommendations to the Minister of Energy and Mines. The provincial Cabinet makes the final decision to approve or reject rates.

Under the 1988 Manitoba Environment Act, the provincial government must also approve major facility construction. Applications are made to the Minister of the Environment and a full environmental assessment is required. A description of Manitoba's environmental assessment review process is given in chapter 11.

Saskatchewan

Saskatchewan Power Corporation (SaskPower) is governed by a government-appointed Board of Directors that is responsible for the management and operation of the Crown utility. Proposals to increase rates or construct new generation or transmission facilities must be approved by the Board of Directors. The minister responsible for SaskPower is a member of the Board.

Alberta

TransAlta Utilities Corporation and Alberta Power Limited are regulated by the Alberta Energy Resources Conservation Board (ERCB) with respect to the development of generation and transmission facilities, coal mine developments, and changes in service areas. Thermal generating stations are issued permits, which are subject to Lieutenant Governor-in-Council approval, while hydro dam approvals require final authorization through the passage of a bill in the legislature. TransAlta's and Alberta Power's rates are regulated by the Alberta Public Utilities Board, under the provisions of the Public Utilities Board Act of 1980.

As a municipally owned utility, Edmonton Power is subject to the authority of Edmonton Council, as well as the various provincial regulatory bodies. Its rates and financing are regulated by city council, while the ERCB is responsible for the regulation of new generation and transmission facilities.

The three utilities participate in the cost-pooling program of the Electric Energy Marketing Agency (EEMA). The EEMA was established in 1982 by the provincial government to help equalize power costs throughout Alberta. Under EEMA legislation, the utilities' generation and transmission costs are regulated by the Public Utilities Board. The Board also approves the selling prices of electricity to EEMA, which then pools the utilities' costs and resells the power at average prices back to the utilities.

British Columbia

Electricity rate changes in the province of British Columbia require the approval of the British Columbia Utilities Commission (BCUC). Major generation and transmission projects require the approval of the provincial Cabinet. Upon receiving an application to construct a major facility, the government may refer the application to the BCUC for review and a recommended course of action. Projects which obtain Cabinet approval receive an Energy Project Certificate from the province.

Yukon and Northwest Territories

As noted in chapter 1, the federal government has sold the assets of the Northern Canada Power Commission (NCPC) to the territorial governments. The Yukon transfer was completed in 1987. The Yukon Energy Corporation, which is now the principal electrical utility in the territory, is subject to the regulations of the Yukon Utility Board, under the Public Utilities Act of 1986. Under the Act, the Corporation must file applications for rate changes or facility construction with the Board. The Board then reviews the application and makes a decision on the request.

The transfer of the NCPC to the Northwest Territories Power Corporation was completed in May 1988. The regulation of rates and new facilities is currently by the Government of the Northwest Territories. The N.W.T. Public Utilities Board Act is presently being revised, and it is expected that once the revision is complete, the N.W.T. Power Corporation will be regulated by the territorial Public Utilities Board. The scheduled date for completion of the revision is late 1989.

4. Electricity Consumption

ELECTRICITY AND PRIMARY AND SECONDARY ENERGY

Electricity constitutes a significant share of Canada's primary and secondary energy consumption. Primary energy refers to the amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves. Conversion losses refer to losses in the processing of refined petroleum products, for example, or losses due to thermal and mechanical inefficiencies resulting from the conversion of fossil fuels (coal, oil or natural gas) into electricity in thermal power generation. The contribution of electricity to total primary energy consumption has steadily increased from 29 per cent in 1960 to 45 per cent in 1987, as shown in Figure 4.1. In terms of volume, primary energy consumption delivered in the form of electricity increased from 1153 PJ in 1960 to 4739 PJ in 1987, an average annual growth of 5.4 per cent. This is about double the average annual growth of non-electric primary energy consumption of 2.7 per cent registered for the same period.

Secondary energy is the amount of energy available to, and used by, the consumer in its final form. Electricity constitutes a much smaller share of secondary energy consumption than primary energy consumption. Figure 4.2 indicates that electricity's share of Canadian secondary energy consumption was 11 per cent in 1960, and 24 per cent in 1987.

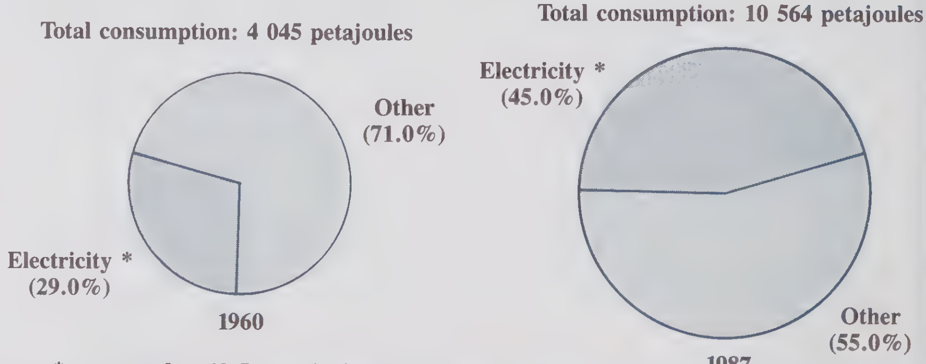
TOTAL ELECTRICITY CONSUMPTION

Total electricity consumption (demand) includes generation by electric utilities, generation by industrial establishments, and net imports (imports minus exports). Table 4.1 indicates that from 1960 to 1987, Canada's total electricity consumption has increased at an average annual rate of 5.3 per cent. For the period 1960-74, growth was rapid and fluctuated within a fairly narrow range, with an average annual growth rate of 6.6 per cent. After the first oil crisis of 1973-74, however, the growth rate declined to 4.2 per cent per year. In 1987, consumption increased by 3.9 per cent, up slightly from 3.7 per cent in 1986.

Of the total electricity consumed in Canada in 1987, 41 per cent was consumed in the industrial sector, 29 per cent in the residential sector, 22 per cent in the commerical sector, and 8 per cent in transmission and distribution losses, as shown in Table 4.2. Since 1960, consumption has grown steadily and most rapidly in the commercial sector (averaging 7.8 per cent per year from 1960 to 1987), while the industrial sector has experienced the lowest growth (averaging 3.7 per cent per year). In 1960, industrial consumption accounted for 60 per cent of total electricity consumption; since then it has gradually decreased and now appears to have stabilized around 42 per cent.

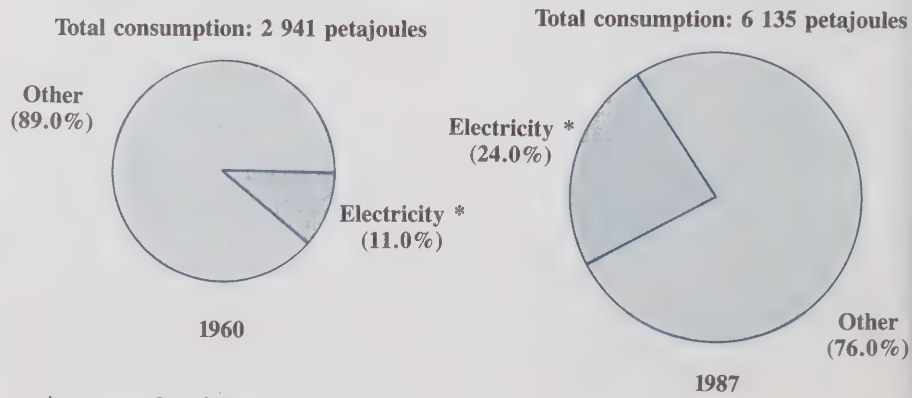
Electricity generation, trade, and consumption by province are given in Table 4.3. Quebec was the largest producing and consuming

Figure 4.1. Primary energy consumption in Canada



* converted at 10.5 megajoules per kilowatt hour

Figure 4.2. Secondary energy consumption in Canada



* converted at 3.5 megajoules per kilowatt hour

province in 1987, and also the largest international exporter. Total electricity generation, consumption, and net transfers are shown in Figure 4.3.

PER CAPITA ELECTRICITY CONSUMPTION

Table 4.4 reports per capita electricity consumption by province. As in the case of total consumption, per capita electricity consumption exhibited a high and low growth pattern before and after the oil crisis of 1973-74. For the period 1960-87, Saskatchewan had the highest growth rate of per capita electricity consumption, with an average of 7.5 per cent, followed by Prince Edward Island with 7.2 per cent, New Brunswick with 6.9 per cent, and Alberta with 6.6 per cent.

Table 4.1. Electricity consumption by province

	Electricity consumption (GW.h)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1986	1987*	1960-74	1975-87	1960-87	1986-87
Nfld.	1 427	2 684	4 770	6 206	8 545	9 658	9 712	9 697	11.5	3.8	7.4	-0.2
P.E.I.	79	137	250	421	518	578	622	647	11.9	3.7	8.1	4.0
N.S.	1 733	2 502	3 706	5 697	6 814	7 626	7 942	8 326	8.7	3.2	6.0	4.8
N.B.	1 684	2 905	4 221	6 713	8 838	10 514	11 658	12 376	10.1	5.2	7.7	6.2
Que.	44 002	52 229	69 730	89 932	118 254	144 761	151 838	158 196	5.4	4.8	4.9	4.2
Ont.	37 157	49 276	69 488	89 197	106 509	122 460	126 936	132 174	6.4	3.3	4.8	4.1
Man.	4 021	5 942	8 601	11 890	13 927	15 912	16 217	15 862	7.9	2.4	5.2	-2.2
Sask.	2 124	3 449	5 402	7 187	9 827	12 050	11 961	12 451	9.2	4.7	6.8	4.1
Alta.	3 472	5 603	9 880	15 246	23 172	33 295	34 659	36 588	10.7	7.5	9.1	5.6
B.C.	13 413	19 170	25 761	32 689	42 789	49 150	49 394	50 934	6.9	3.8	5.1	3.1
Yukon	89	109	220	352	381	252	344	433	9.3	1.7	6.0	25.6
N.W.T.	100	159	308	425	494	594	535	466	10.2	0.8	5.9	-12.7
Canada	109 304	144 165	202 337	265 955	340 068	406 859	421 818	438 150	6.6	4.2	5.3	3.9

* *Preliminary data.*

Source: Electric Power Statistics, Volume II, *Statistics Canada, catalogue 57-202.*

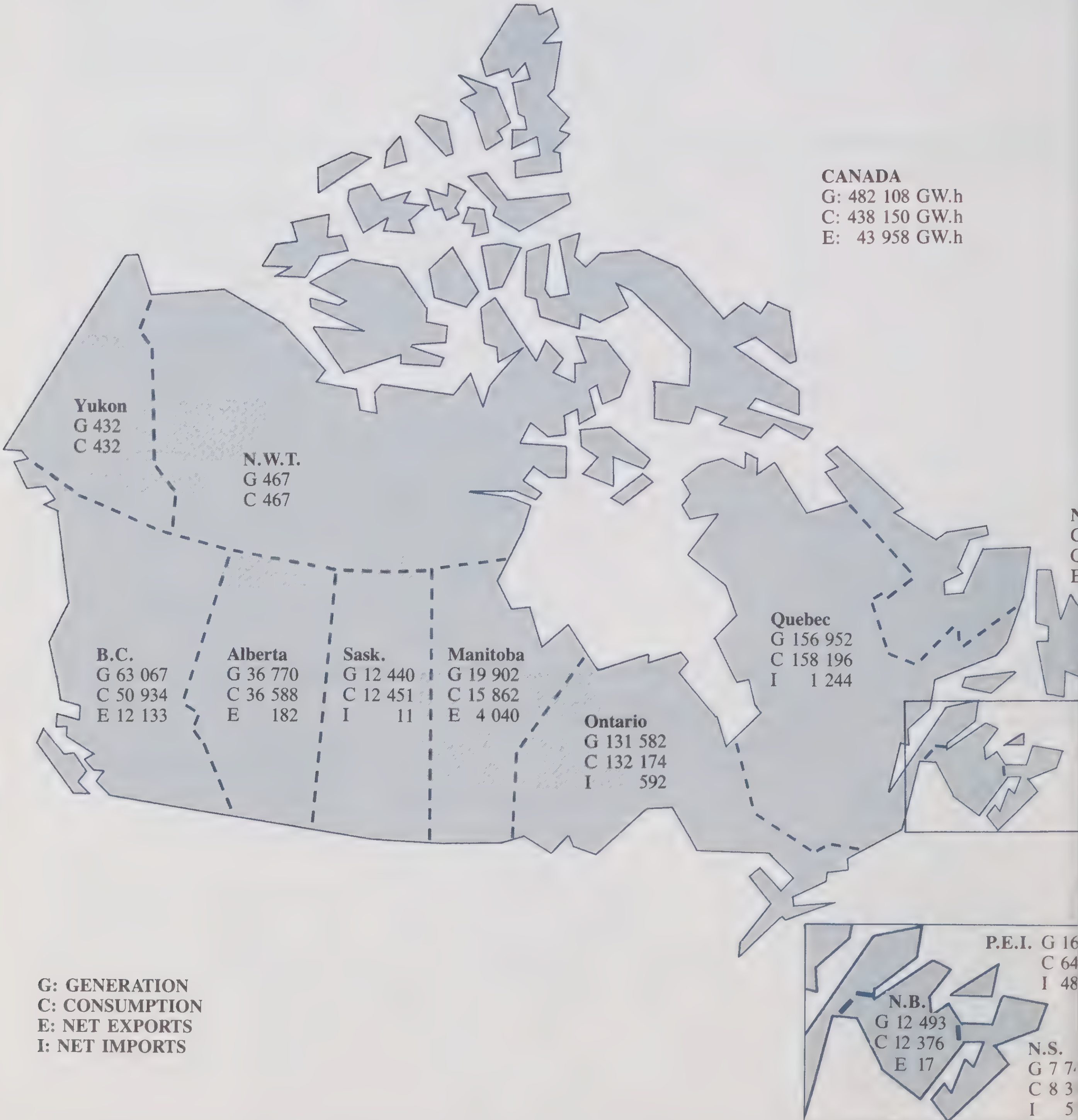
Table 4.2. Electricity consumption in Canada by sector

	Electricity consumption (GW.h)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1986	1987*	1960-74	1975-87	1960-87	1986-87
Residential	20 397 (19)	29 738 (20)	43 431 (21)	64 128 (24)	92 440 (27)	113 983 (28)	117 905 (28)	126 993 (29)	7.9	5.9	7.0	7.7
Commercial	12 632 (12)	23 859 (17)	44 068 (22)	65 744 (25)	75 912 (21)	85 320 (21)	92 148 (22)	96 927 (22)	12.4	3.3	7.8	5.2
Industrial	66 353 (60)	79 118 (55)	98 450 (49)	109 743 (41)	142 247 (42)	171 803 (42)	175 507 (42)	177 367 (41)	4.3	4.1	3.7	1.1
*Line losses***	9 920 (9)	11 450 (8)	16 388 (8)	26 340 (10)	32 469 (10)	35 753 (9)	36 258 (8)	36 863 (8)	6.5	2.8	5.0	1.7
Total	109 304 (100)	144 165 (100)	202 337 (100)	265 955 (100)	340 068 (100)	406 859 (100)	421 818 (100)	438 150 (100)	6.6	4.2	5.3	3.9

* *Preliminary data.*
** *Losses during transmission and distribution.*
Figures in parentheses are percentage shares.

Source: Electric Power Statistics, Volume II, *Statistics Canada, catalogue 57-202.*

Figure 4.3. Electricity generation, consumption and net transfers, 1987 (GW.h)



In 1987, Quebec was the largest electricity user in Canada with 23 720 kW.h per person, while Prince Edward Island was the smallest with 5043 kW.h per person. Quebec's per capita consumption was 39 per cent above the national average, while Prince Edward Island's was 71 per cent below the average. Quebec, British Columbia, New Brunswick, and the Yukon were the areas in which per capita consumption levels in 1987 were higher than the national average.

ECONOMIC GROWTH AND ELECTRICITY CONSUMPTION

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, technological changes, and weather. However, aggregate economic activity (as

Table 4.3. Provincial electricity generation, trade and consumption, 1987

		Imports from		Exports to		
	Generation	Provinces	U.S.A.*	Provinces	U.S.A.*	Consumption
Nfld.	40 090	0	0	30 393	0	9 697
P.E.I.	164	483	0	0	0	647
N.S.	7 749	659	0	82	0	8 326
N.B.	12 493	6 922	266	1 164	6 141	12 376
Que.	156 952	30 427	0	12 782	16 401	158 196
Ont.	131 582	6 992	2 113	16	8 497	132 174
Man.	19 902	1 220	512	2 311	3 461	15 862
Sask.	12 440	1 262	84	1 222	113	12 451
Alta.	36 770	526	2	710	0	36 588
B.C.	63 067	710	493	521	12 815	50 934
Yukon	432	0	0	0	0	432
N.W.T.	467	0	0	0	0	467
Canada	482 108	49 201	3 470	49 201	47 428	438 150

** Service exchange is included.*

Source: Energy, Mines and Resources Canada.

Table 4.4. Per capita electricity consumption by province

	Per capita consumption (kW.h/person)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1986	1987	1960-74	1975-87	1960-87	1986-87
Nfld.	3 184	5 500	9 226	11 304	14 758	16 632	16 739	16 745	10.1	3.3	6.3	0.0
P.E.I.	765	1 257	2 273	3 598	4 177	4 608	4 852	5 043	11.1	2.9	7.2	3.9
N.S.	2 385	3 310	4 739	6 948	7 988	8 668	8 986	9 370	7.9	2.5	5.2	4.3
N.B.	2 864	4 724	6 732	10 095	14 850	16 058	16 167	17 115	9.2	4.5	6.9	5.9
Que.	8 565	9 187	11 597	14 555	18 735	21 991	22 911	23 720	4.1	4.2	3.8	3.5
Ont.	6 086	7 259	9 203	10 915	12 422	13 510	13 825	14 205	4.3	2.2	3.2	2.8
Man.	4 932	6 158	8 750	11 726	13 521	14 863	15 035	14 649	6.3	1.9	4.1	-2.6
Sask.	1 750	3 631	5 741	7 924	10 131	11 839	11 715	12 169	11.6	3.6	7.5	3.9
Alta.	2 695	3 864	6 194	8 575	11 135	14 120	14 505	15 277	8.4	4.9	6.6	5.3
B.C.	8 386	10 680	12 124	13 433	16 220	17 038	16 998	17 356	3.9	2.2	2.7	2.1
Yukon	4 589	7 569	11 957	16 526	17 085	10 862	15 026	18 633	8.7	1.0	5.3	24.0
N.W.T.	5 304	5 540	8 851	10 316	11 052	11 647	10 507	9 174	3.5	-1.0	2.1	-12.7
Canada	6 184	7 339	9 501	11 718	13 112	16 043	16 633	17 121	4.9	3.2	3.8	2.9

Source: Electrical Energy Branch, Energy, Mines and Resources Canada.

measured by the Gross Domestic Product) is the most important variable. The historical relationship between per capita GDP and per capita electricity consumption is shown in Figure 4.4.

PEAK DEMAND

Peak demand is the annual maximum average net kilowatt load of one hour duration within an electrical system. For Canada as a whole, as shown in Table 4.5, peak demand grew from 17 264 MW in 1960 to 71 418 MW in 1987, an average annual growth rate of 5.4 per cent. In comparison, total consumption during the same period grew at an average annual rate of 5.3 per cent. In 1987, peak demand grew 1.9 per cent, up from a negative growth rate of 1.3 per cent in 1986.

LOAD FACTOR

Load factor is defined as the ratio of average demand to peak demand in any given period. More precisely, it is the energy demand in kilowatt-hours divided by the product of the number of hours in the period multiplied by the peak demand in kilowatts. (In a year-base average, demand equals annual energy consumption divided by 8760 hours per year.)

Table 4.6 indicates that for the electric power industry in Canada as a whole, load factor has declined since 1960. At that time the industry load factor was 72.3 per cent. This was gradually reduced to about 67 per cent in 1970, and to 66 per cent in 1980. In 1987, it was 70 per cent.

Figure 4.4. Historical relationship between electricity demand and GDP, 1960-1987

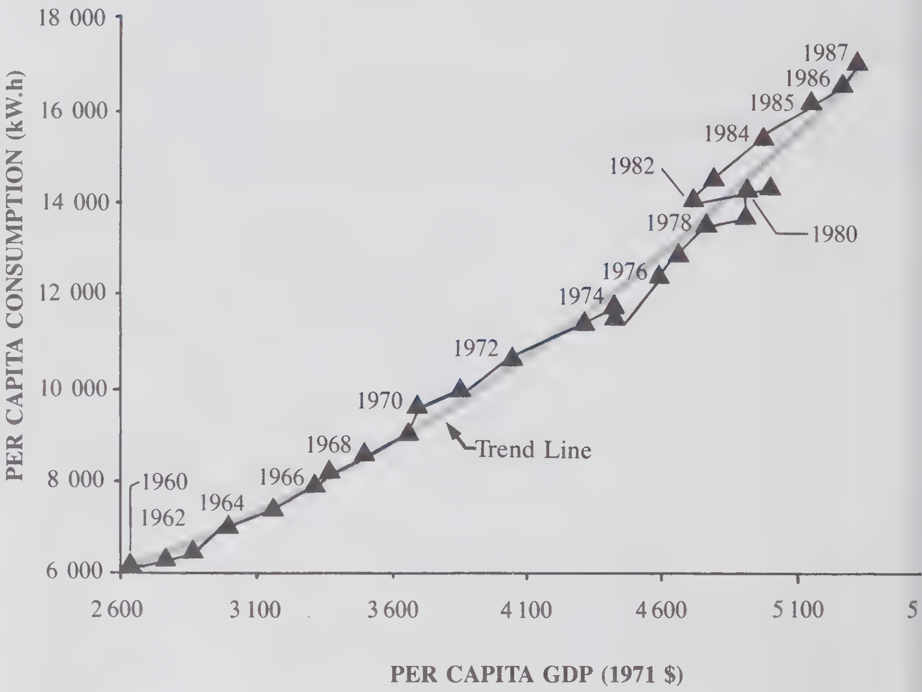


Table 4.5. Peak demand by province

	Peak demand (MW)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1986	1987*	1960-74	1975-87	1960-87	1986-87
Nfld.	245	422	763	1 031	1 538	1 510	1 630	1 570	12.5	1.6	7.1	-3.7
P.E.I.	21	35	55	85	104	93	95	91	11.7	0.6	5.6	-4.2
N.S.	356	457	814	998	1 197	1 360	1 372	1 445	8.6	3.1	5.3	5.3
N.B.	319	528	726	1 101	1 699	1 888	2 063	2 210	10.8	6.0	7.4	7.1
Que.	5 871	8 228	11 127	15 114	20 680	25 618	25 049	25 885	7.8	4.6	5.7	3.3
Ont.	6 391	8 596	12 048	15 570	17 767	21 533	21 570	21 442	6.5	2.7	4.6	-0.6
Man.	772	1 022	1 565	2 326	2 681	2 932	2 981	2 992	8.3	2.1	5.2	0.4
Sask.	418	653	1 028	1 318	2 085	2 202	2 129	2 126	9.7	4.1	6.2	-0.1
Alta.	714	1 121	1 894	2 713	3 879	5 259	5 233	5 207	11.1	5.6	7.6	-0.5
B.C.	2 123	3 058	4 492	5 797	7 384	8 487	7 800	8 271	8.2	3.0	5.2	6.0
Yukon	19	16	39	66	75	53	69	68	9.4	0.3	4.8	-1.5
N.W.T.	15	31	41	68	81	96	120	111	11.8	4.2	7.7	-7.5
Canada	17 264	24 167	34 592	46 187	59 170	71 031	70 111	71 418	7.8	3.7	5.4	1.9

* *Preliminary data*

Source: Electric Power Statistics, Volume I, *Statistics Canada, catalogue 57-204.*

Table 4.6. Load factor by province

	1960	1965	1970	1975	1980	1985	1986	1987
	(per cent)							
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	68.0	70.5
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	74.7	81.2
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	66.1	65.8
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	64.5	63.9
Que.	85.6	72.5	71.5	67.9	65.3	64.5	69.2	69.8
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	67.2	70.4
Man.	59.5	66.4	62.7	58.4	59.3	62.0	62.1	60.5
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	64.1	66.9
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	75.6	80.2
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	72.3	70.3
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	56.9	72.7
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	50.9	47.9
Canada	72.3	68.1	66.8	65.7	65.6	65.1	68.5	70.0

Source: Calculated from Electric Power in Canada, 1987, *Tables 4.1 and 4.5.*

A SaskPower transmission line maintenance crew changes a damaged insulator on the 230-kV line from Resdin, Manitoba, to Boundary Dam power station near Estevan.

5. Electricity Generation

SOURCES OF GENERATION

Canada's electric power industry began in the 1880s with electricity generated by steam. In the beginning, electricity was used mainly for home and street lighting. In the late 1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industry needs 24 hours a day. Following this, hydroelectric development spread rapidly, due to Canada's abundance of water resources. In 1920, hydro accounted for more than 97 per cent of total electricity production in Canada. This percentage declined slightly to 95 per cent by 1950, and 92 per cent by the end of 1960. By 1987, hydro production had further declined to 65 per cent.

Although thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry, for many years its share of total production did not increase significantly because of its relatively high cost of production. However, by the 1960s and 1970s, when most of Canada's economical hydro sites had been developed, the situation changed and thermal generation became competitive. Between 1950 and 1974, the growth rates of real fossil-fuel prices (coal, oil, and natural gas) were negative, and this led most electric utilities to consider building more thermal stations. As Table 5.1 indicates, thermal generation accounted for only 7 per cent of the total generated electricity in 1960. However, its production share jumped to 19 per cent by 1965, 23 per cent by 1970, and reached a peak of 25 per cent in 1974. After the first oil crisis of 1973-74, the share of thermal production gradually declined to 22 per cent by 1980, 20 per cent by 1985, and then stabilized at 20 per cent at the end of 1987.

After 1975, nuclear production emerged as an important source of electricity generation in Canada. Canadian nuclear power began in 1962 when the 25-MW Rolphton station went into operation in Ontario. In 1965, nuclear generation totalled only 88 GW.h, accounting for less than 0.1 per cent of total generated electricity in Canada. By 1975, nuclear generation accounted for more than 4 per cent of total electricity production. Most of the nuclear generation came from the first four Pickering stations in Ontario, which were completed between 1971-73.

By 1980, the nuclear production share increased to about 10 per cent of Canada's total with the completion of four of Ontario's Bruce stations, which were commissioned during the period 1976-79.

By 1985 nuclear generation accounted for 13 per cent of Canada's total generated electricity. During the period 1980-85, seven new nuclear stations were brought into service. They were Gentilly 2 in Quebec; Point Lepreau in New Brunswick; and Pickering stations 5, 6, and 7 and Bruce stations 5 and 6, all located in Ontario. In 1987, Pickering 8 and Bruce 7 went into operation, increasing the nuclear generation share to 15 per cent of Canada's total production.

Tidal power has to date played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America.

Electricity generation increased 5.8 per cent in 1987 to 482 108 GW.h. Of this total, 438 150 GW.h was for use in Canada, and the remainder was exported. The sources of generation are given in Table 5.1, and the major generating

Table 5.1. Sources of electricity generation

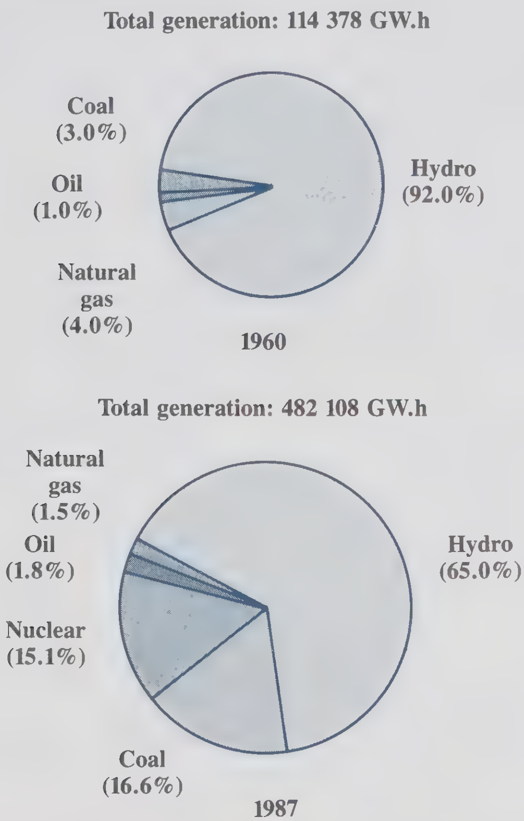
	Electricity Generation								Average annual growth rate			
Fuel Type	**1960**	**1965**	**1970**	**1975**	**1980**	**1985**	**1986**	**1987**	**1960-74**	**1975-87**	**1960-87**	**1986-87**
	(GW.h)								(per cent)			
Hydro	105 883	117 063	156 709	202 396	251 217	301 250	307 593	313 189	5.1	3.7	4.1	1.8
Thermal	8 495	27 123	47 045	59 138	80 207	88 842	80 936	96 031	14.3	4.1	9.4	18.7
*Nuclear**	-	88	969	11 858	35 882	57 067	67 233	72 888	-	16.3	-	8.4
*Tidal***	-	-	-	-	-	23	33	30	-	-	-	-9.1
Total	114 378	144 274	204 723	273 392	367 306	447 182	455 795	482 108	6.6	4.8	5.5	5.8

* *Commercial operation started in 1968.*
** *Commercial operation started in 1984.*

Source: Electric Power Statistics, Volume II, *Statistics Canada, Catalogue 57-202.*

Figure 5.1. Major generating stations by province, 1987 (MW)

Figure 5.2. Electricity generation by fuel type



stations in each province are shown in Figure 5.1.

Between 1960 and 1987, the share of hydro production dropped 27 percentage points, from 92 per cent to 65 per cent, as shown in Figure 5.2. The natural gas production share also decreased, from 4 per cent in 1960 to 1.5 per cent in 1987. The oil share has increased slightly, from 1 per cent to 1.8 per cent over the same period. Nuclear production had the largest gain, from zero in 1960 to 15 per cent by 1987, while the coal production share increased from 3 per cent in 1960 to about 17 per cent by 1987.

Electrical energy production by fuel type in 1987 is reported in Table 5.2. In Newfoundland, Quebec, Manitoba, British Columbia, and the Yukon Territory, hydro generation accounted for more than 94 per cent of the total. In Alberta, about 83 per cent of total generation came from coal-fired stations. Coal generation was also quite important in Saskatchewan and Nova Scotia, at 72 per cent and 70 per cent respectively.

Table 5.2. Electrical energy production by fuel type, 1987

	Coal	Oil	Natural Gas	Nuclear	Hydro	Total
			(GW.h)			
Newfoundland	0	2 317	0	0	37 773	40 090
Prince Edward Island	108	56	0	0	0	164
Nova Scotia	5 436	1 539	0	0	774	7 749
New Brunswick	1 452	3 710	0	5 112	2 219	12 493
Quebec	0	182	0	4 660	152 110	156 952
Ontario	32 291	47	1 524	63 116	34 604	131 582
Manitoba	577	7	7	0	19 311	19 902
Saskatchewan	8 931	12	309	0	3 188	12 440
Alberta	30 514	130	4 676	0	1 450	36 770
British Columbia	961	470	579	0	61 057	63 067
Yukon	0	24	0	0	409	432
Northwest Territories	0	172	0	0	294	467
Canada	80 270	8 666	7 095	72 888	313 189	482 108

Source: Energy, Mines and Resources Canada.

Ontario, Quebec, and New Brunswick are the only three provinces with nuclear energy in Canada. In 1987, nuclear generation accounted for 48 per cent of Ontario's total electricity generation, 41 per cent of New Brunswick's, and 3 per cent of Quebec's. Electricity generation from natural gas occurs mainly in industries that generate power for their own use. In all provinces except Newfoundland, Nova Scotia, and New Brunswick, oil is used mainly for peaking purposes.

GENERATION BY PROVINCE

Table 5.3 shows electricity generation by province during the period 1960-87, and generation growth rates for 1987 over 1986 and the period 1960-87. Newfoundland had the greatest production growth during the period 1960-87, with an average annual growth rate of 12.9 per cent. This was due mainly to the completion of the Churchill Falls hydro station (5429 MW) in Labrador in 1974.

Electricity generation fluctuated significantly in Prince Edward Island during the period 1960-87. The province's electrical generating plants are relatively small and are fuelled by oil, and are consequently expensive to operate. In 1977, an interprovincial interconnection was completed, allowing P.E.I. to purchase electrical energy from New Brunswick. In addition, in 1981 P.E.I. purchased a 10-per cent ownership interest in the 200-MW coal/oil-fired plant at Dalhousie, N.B. Because of the interconnection and joint ownership, P.E.I. has been able to reduce the amount of generation from its oil-fired stations.

In 1987, electricity generation in British Columbia increased by more than 24 per cent due to export sales to the United States. Meanwhile, Manitoba experienced a 17.3 per cent drop in total generation because of poor water conditions in the province.

Figure 5.3 presents electricity generation by region. Although Quebec has been the largest electricity producer in Canada since 1960, its share has declined from 44 per cent of the total in 1960 to about 33 per cent by 1987; Ontario was second with 27 per cent in 1987, compared with 31 per cent in 1960; and British Columbia was third with 13 per cent in 1987, slightly greater than the 12 per cent registered in 1960.

FOSSIL-FUEL REQUIREMENTS

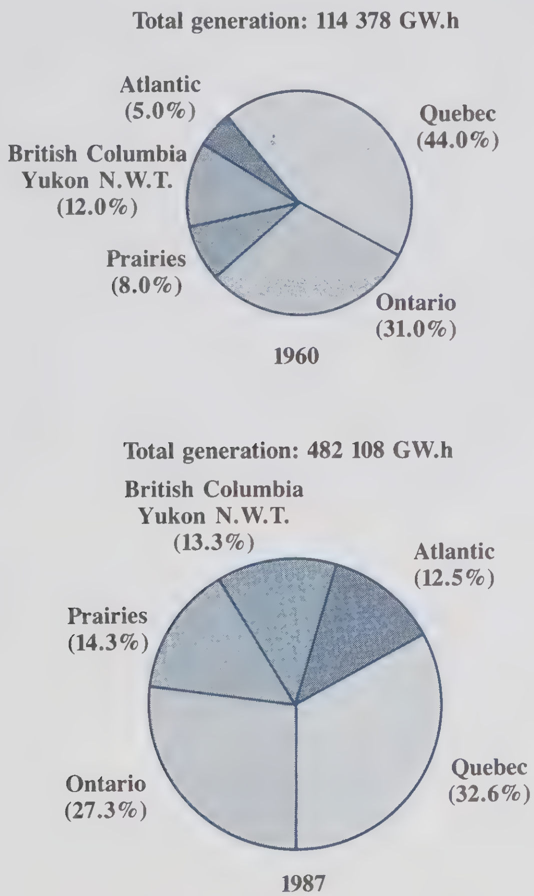
Table 5.4 reports fuel use during the period 1960-87. Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased about nine times during the period 1960-75, and more than doubled during the following ten years. However, coal used to generate electricity has fluctuated recently: 40 million tonnes in 1985; 38 million tonnes in 1986; and 43 million tonnes in 1987. The largest increase in coal use in 1987 occurred in Ontario. The use of natural gas and oil for electricity generation peaked in the mid-1970s and early 1980s, and then declined substantially. The increased use of oil and natural gas for electricity generation in 1987

Table 5.3. Sources of electricity by province

	Electricity Generation								Average annual growth rate			
	1960	1965	1970	1975	1980	1985	1986	1987	1960-74	1975-87	1960-87	1986-87
	(GW.h)								(per cent)			
Nfld.	1 512	2 769	4 854	35 803	46 374	41 494	40 407	40 090	23.4	1.0	12.9	-0.8
P.E.I.	79	137	250	421	127	2	151	164	11.9	-7.6	2.7	8.6
N.S.	1 814	2 632	3 511	5 498	6 868	7 457	7 401	7 749	8.2	2.9	5.5	4.7
N.B.	1 738	2 960	5 142	4 677	9 323	11 401	12 057	12 493	8.7	8.5	7.6	3.6
Quebec	50 433	57 005	75 877	76 108	97 917	137 028	148 261	156 952	3.7	6.2	4.3	5.9
Ontario	35 815	44 858	63 857	78 558	110 283	121 783	125 195	131 582	6.2	4.4	4.9	5.1
Manitoba	3 742	5 489	8 449	14 818	19 468	22 777	24 054	19 902	10.2	2.5	6.4	-17.3
Sask.	2 204	3 733	6 011	7 090	9 204	11 838	11 913	12 440	9.0	4.8	6.6	4.4
Alberta	3 443	5 591	10 035	15 100	23 451	33 432	34 719	36 770	10.8	7.7	9.2	5.9
B.C.	13 409	18 832	26 209	34 542	43 416	59 124	50 758	63 067	7.4	5.1	5.9	24.3
Yukon	89	121	224	352	381	252	344	432	9.3	1.7	6.0	25.6
N.W.T.	100	147	304	425	494	594	535	467	10.2	0.8	5.9	-12.7
Canada	114 378	144 274	204 723	273 392	367 306	447 182	455 795	482 108	6.6	4.8	5.5	5.8

Source: Electric Power Statistics, Volume II, *Statistics Canada, Catalogue 57-202.*

Figure 5.3. Electricity generation by region



can be attributed mainly to the collapse of world oil prices. The use of uranium has increased dramatically since 1970 with the growth of nuclear capacity in Canada.

Electricity generated from conventional thermal and nuclear sources totalled about 168 919 GW.h in 1987, or about 35 per cent of total generation. In terms of heat content, fuels used for this generation amounted to the equivalent of 291 million barrels of oil. A breakdown of the fuels used by utilities is provided in Table 5.5. Ontario was the largest user, accounting for approximately 50 per cent of the total. Alberta was second, accounting for 27 per cent, and Saskatchewan ranked third with a 10-per cent share.

New Brunswick remained the largest user of oil, followed by Newfoundland and Nova Scotia. All three provinces are still using oil for base-load generation.

Alberta is the largest user of coal for electricity generation, accounting for 43 per cent of the coal used in Canada for electricity generation.

Energy sources of electricity generation changed significantly in 1987 from the previous year. The

Table 5.4. Fuels used to generate electricity in Canada

	1960	1965	1970	1975	1980	1985	1986	1987
Coal (10^3 tonnes)	1 674	7 004	13 786	16 567	27 785	39 456	37 562	42 500
Oil (10^3 cubic metres)	328	871	1 869	2 309	2 867	1 391	1 301	2 054
Natural gas (10^6 cubic metres)	1 069	1 679	1 992	4 009	1 875	1 223	2 571	2 979
Uranium (tonnes)	0	2	16	194	685	1 086	1 276	1 306

Source: Electric Power Statistics, Volume II, *Statistics Canada, Catalogue 57-202.*

Table 5.5. Fossil fuels used by utilities, 1987

	Coal (10^3 tonnes)	Oil (cubic metres)	Gas (10^6 cubic metres)	Uranium (tonnes)
Nfld.	0	595 002	0	0
P.E.I.	46	25 900	0	0
N.S.	2 225	343 044	0	0
N.B.	526	885 103	0	99
Que.	0	74 928	0	87
Ont.	13 373	57 203	923	1 120
Man.	457	349	6	0
Sask.	7 672	2 401	91	0
Alta.	18 201	31	1 850	0
B.C.	0	61	98	0
N.W.T.	0	1 005	11	0
Yukon	0	8 873	0	0
Canada	42 500	2 053 905	2 979	1 306

Note: 1 cubic metre oil = 6.3 barrels
1 cubic metre gas = 35.5 cubic feet
1 tonne = 1000 kilograms

Source: Energy, Mines and Resources Canada.

increase in coal use, from 38 million tonnes in 1986 to about 43 million tonnes in 1987, is attributed mainly to a 32 per cent increase in coal-fired generation in Ontario.
Oil use also increased, up from 8.2 million barrels in 1986 to 12.9 million barrels in 1987. Most of this increase occurred in Newfoundland, Nova Scotia, and New Brunswick. The collapse of world oil prices in 1987 provided an economic incentive for these three provinces to use more oil-fired stations for electricity generation. Uranium use increased with the addition of Ontario's Bruce 8 station, and the return to service of the Pickering 1 nuclear reactor, following a shutdown for retubing. Natural gas use increased moderately, with most of the increase occurring in Ontario and Alberta.

In 1987, provinces west of Quebec continued to use Canadian oil, primarily light oil and diesel oil, in gas turbines or diesel plants. In the Yukon and Northwest Territories, Canadian diesel oil was used to supply electricity to small remote communities. Oil used by the Atlantic region and Quebec was imported.

In 1987, about 65 per cent of the coal used for electricity generation in Ontario was imported from the United States, while the remainder came from western Canada. Coal used by Manitoba was purchased from Saskatchewan, while Alberta, Nova Scotia, and New Brunswick used their own coal resources. Saskatchewan relied primarily on its own coal, but also purchased additional amounts from Alberta.

Hydro-Québec's system control centre in Montreal is the core of its operations, ensuring effective management of the utility's vast grid.

6. Generating Capacity and Reserve

In 1987, more than half of Canada's installed generating capacity was hydro. Conventional thermal (coal, oil, and natural gas) constituted a further 30.7 per cent, while nuclear supplied the remaining 11.9 per cent.

Table 6.1 reports installed generating capacity by fuel type for Canada during the period 1960-87. Figure 6.1 illustrates the change in Canada's installed capacity by principal fuel type between 1960 and 1987.

The most significant change in the 1960-87 period has been the decline in the relative share of hydro capacity, from 81 per cent in 1960 to 57.4 per cent in 1987. The decline in hydro's share has been matched by an increase in the share taken by coal (from 9.0 per cent to 17.8 per cent) and nuclear (zero to 11.9 per cent). The share taken by oil and natural gas has not changed significantly over the period.

CAPACITY ADDITIONS

Because most electric utilities in Canada currently have surplus capacity, there was only one major capacity addition in 1987. On May 22, 1987, the eighth and final unit at the Bruce nuclear power

Figure 6.1. Installed generating capacity by fuel type

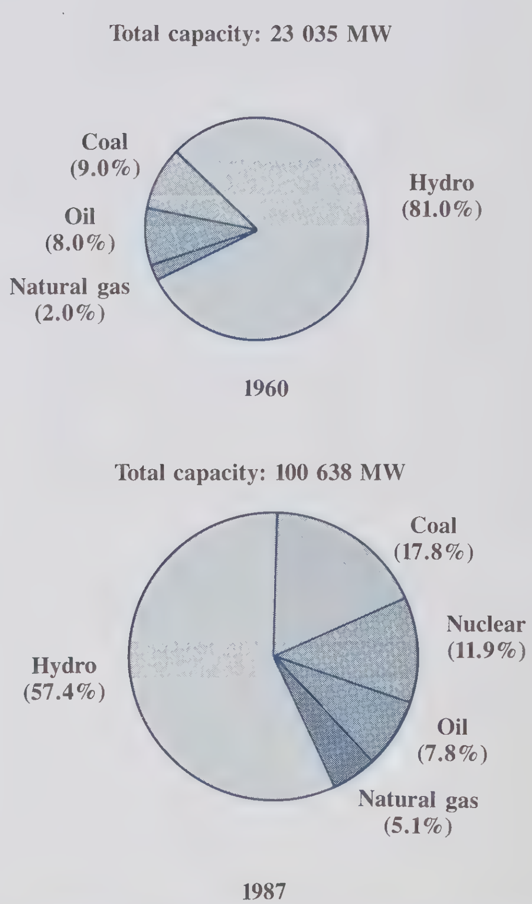


Table 6.1. Installed generating capacity by fuel type, 1960-1987

Fuel Type	Installed Generating Capacity								Average annual growth rate			
	1960	1965	1970	1975	1980	1985	1986	1987	1960-74	1975-87	1960-87	1986-87
	(MW)								(per cent)			
Hydro	18 643	21 771	28 298	37 282	47 770	57 711	57 711	57 711	5.0	3.7	4.3	0.0
Thermal	4 392	7 557	14 287	21 404	28 363	30 476	30 980	30 979	11.7	3.2	7.5	0.0
*Nuclear**	0	20	240	2 666	5 866	10 664	11 098	11 928	-	12.8	-	7.5
*Tidal***	0	0	0	0	0	20	20	20	-	-	-	0.0
Total	23 035	29 348	42 826	61 352	81 999	97 020	99 809	100 638	6.8	4.2	5.6	0.8

* *Commercial operation started in 1968.*
** *Commercial operation started in 1984.*

Source: Electric Power Statistics, Volume II, *Statistics Canada, Catalogue 57-202.*

evelopment in Ontario was eclared in-service. The 837-MW eactor brings the total capacity of he Bruce generating complex to 402 MW.

APACITY BY FUEL TYPE AND ROVINCE

otal installed capacity by principal fuel type and province for 987 is given in Table 6.2. Installed apacity by region from 1960 to 987 is shown in Figure 6.2. igure 6.2 indicates that in 1960 uebec's installed capacity was the argest in Canada, with 39 per cent f the total, followed by Ontario with 31 per cent, and British olumbia with 13 per cent. In 1987, uebec was in second place, ehind Ontario. Quebec's capacity hare was 27.5 per cent in 1987, while Ontario's share was 32 per ent. The Atlantic provinces ad the major gain; their share ncreased from 5 per cent in 1960 to 3.3 per cent by 1987. The increase was due largely to the completion f the Churchill Falls project in 1974, which added significantly to Newfoundland's installed capacity.

Figure 6.2. Installed generating capacity by region

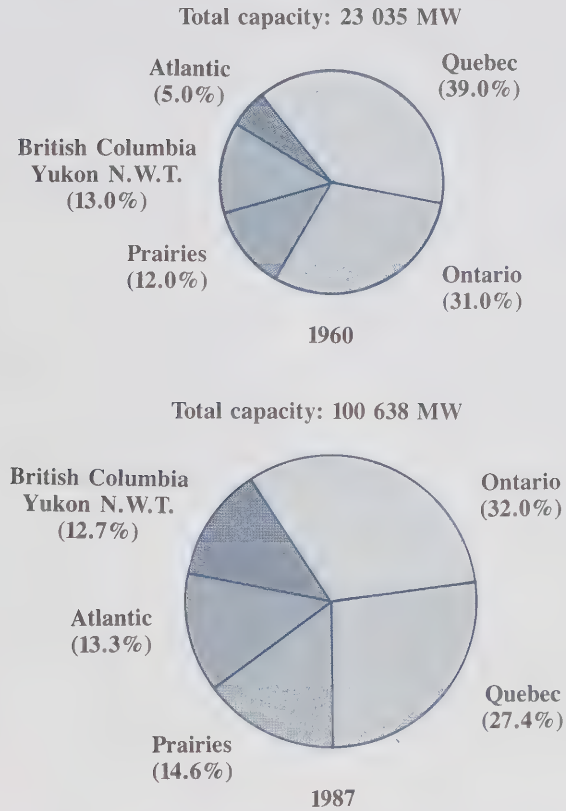


Table 6.2. Installed generating capacity by fuel type and province, 1987

	Hydro	Coal	Nuclear	Oil	Natural Gas	Total
			(MW)			
Nfld.	6 644	0	0	758	0	7 402
P.E.I.	0	20	0	102	0	122
N.S.	386	954	0	1 006	0	2 346
N.B.	903	307	680	1 600	0	3 490
Que.	25 849	0	685	1 110	0	27 644
Ont.	7 764	9 600	10 563	2 673	1 523	32 123
Man.	3 641	442	0	50	4	4 137
Sask.	830	1 815	0	7	296	2 948
Alta.	734	4 586	0	80	2 205	7 605
B.C.	10 848	0	0	551	1 109	12 508
Yukon	82	0	0	41	0	123
N.W.T.	50	0	0	120	20	190
Canada	57 731	17 724	11 928	8 098	5 157	100 638

Source: Electric Power Statistics, Volume II, *Statistics Canada, Catalogue 57-204.*
Energy, Mines and Resources Canada.

Table 6.3 presents total installed capacity by province during the period 1960-87, along with a comparison of the annual growth rates for the various periods. As with energy generation, capacity growth during the period 1960-74 was substantially larger than for the period 1975-87. For Canada as a whole, the growth rate for capacity before the first oil crisis was much larger than that after the oil crisis. For the period 1960-87, Newfoundland had the largest capacity growth rate with 12.4 per cent, followed by New Brunswick with 8.3 per cent, and Alberta with 8.2 per cent. Quebec had the smallest growth rate for installed capacity during the same period, with 4.3 per cent.

MAJOR HYDRO PLANTS IN CANADA

Table 6.4 reports the ten hydro plants in Canada with the largest capacity in 1987. Churchill Falls was the largest hydro station with 5429 MW, followed by La Grande 2 with 5328 MW, and La Grande 4 with 2651 MW. Five of the ten hydro plants are located in Quebec, three in British Columbia, and one each in Newfoundland and Ontario. These ten hydro stations have a total installed capacity of 25 926 MW, and they accounted for about 45 per cent of Canada's total hydro capacity in 1987.

MAJOR CONVENTIONAL THERMAL STATIONS IN CANADA

The ten largest thermal stations are given in Table 6.5. The largest thermal plant in 1987 was the Nanticoke coal-fired station with 4096 MW, followed by Lakeview with 2400 MW, and Lennox with 2295 MW. Seven of the ten stations are using coal as input fuel, two oil, and one natural gas. Five of the ten largest thermal stations are located in Ontario; two are in Alberta; and there is one each in New Brunswick, Saskatchewan, and British Columbia. Total combined capacity for these stations is 17 834 MW, which accounted for 58 per cent of Canada's total conventional thermal installed capacity in 1987.

NUCLEAR POWER IN CANADA

By the end of 1987, there were 18 commercial nuclear power stations in Canada. With the exception of Point Lepreau I in New Brunswick and Gentilly 2 in Quebec, they are all located in Ontario. Table 6.6 reports major nuclear power stations in Canada in order of their commissioning date. Total installed capacity for these nuclear power stations is 11 799 MW, which accounted for 12 per cent of Canada's total installed capacity in 1987.

SURPLUS CAPACITY

As indicated in Table 4.1, there have been two distinct periods in the growth of electricity demand in Canada between 1960 and 1987. From 1960 to 1974, there was a period of rapid growth, with an average annual increase of 6.6 per cent. Following the oil crisis of 1973-74, electricity growth slowed to an average rate of 4.1 per cent for the period 1975-87. Electricity consumption actually declined in 1975 and did not grow in 1982.

Table 6.3. Installed generating capacity by province, 1960-1987

	Installed Generating Capacity								Average Annual Growth Rate			
	1960	1965	1970	1975	1980	1985	1986	1987	1960-74	1975-87	1960-87	1986-87
	(MW)								(per cent)			
Nfld.	314	531	1 248	6 668	7 195	7 316	7 402	7 402	21.4	0.9	12.4	0.0
P.E.I.	37	58	77	118	118	122	122	122	8.6	0.3	4.5	0.0
N.S.	507	631	931	1 263	2 029	2 373	2 346	2 346	6.4	5.3	5.8	0.0
N.B.	402	581	1 201	1 333	2 795	3 479	3 490	3 490	8.9	8.4	8.3	0.0
Quebec	8 920	10 769	14 047	15 037	20 531	26 991	27 644	27 644	3.7	5.2	4.3	0.0
Ontario	7 109	9 292	13 700	21 136	25 796	29 932	31 294	32 123	7.0	3.6	5.7	2.7
Manitoba	1 043	1 407	1 794	2 970	4 142	4 141	4 137	4 137	7.8	2.8	5.2	0.0
Sask.	761	967	1 533	1 833	2 340	2 694	2 948	2 948	6.2	4.0	5.1	0.0
Alberta	915	1 398	2 674	3 585	5 807	7 219	7 605	7 605	9.9	6.5	8.2	0.0
B.C.	2 963	3 627	5 473	7 170	10 525	12 451	12 508	12 508	6.0	4.8	5.5	0.0
Yukon	31	56	58	102	94	123	123	123	5.6	1.6	5.2	0.0
N.W.T.	33	51	89	136	180	177	190	190	9.3	2.8	6.7	0.0
Canada	23 035	29 348	42 826	61 352	81 999	97 019	99 809	100 638	6.8	4.2	5.6	0.8

Source: Electric Power Statistics, Volume II, *Statistics Canada, Catalogue 57-202.*

Table 6.4. Canada's largest hydro stations, 1987

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	La Grande 4	Quebec	2 651	1984
4	Gordon M. Schrum	B.C.	2 416	1979
5	La Grande 3	Quebec	2 302	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 639	1932
9	Manic 5	Quebec	1 292	1970
10	Sir Adam Beck 2	Ontario	1 288	1954

Source: Electric Power Statistics, Volume III, *Statistics Canada, Catalogue 57-206, 1986.*

Table 6.5. Canada's largest conventional thermal stations, 1987

Rank	Name	Fuel Type	Province	Rated Capacity (MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 295	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 000	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	N.B.	1 050	1976
8	Burrard	natural gas	B.C.	913	1962
9	Boundary Dam	coal	Saskatchewan	874	1959
10	Keephills	coal	Alberta	806	1983

Source: Electric Power Statistics, Volume III, *Statistics Canada, Catalogue 57-206, 1986.*

This shift, from a long period of sustained rapid growth to one of slower growth, resulted in excess generating capacity. In the early 1970s, the construction of new generating stations was initiated mainly on the basis of expectations of continuing rapid growth in electricity demand, but also to displace oil-fuelled electricity production. As the growth in demand slowed dramatically in the latter part of the decade, some of these newly constructed stations became surplus to domestic requirements.

In calculating surplus capacity, the net generating capability, rather than net generating capacity, is normally used. Net generating capability measures the expected power of all available generating facilities of the province (or country) at the time of one hour firm peak load. This may differ from the generating capacity measured by the nameplate rating of the equipment (see Table 6.1).

Differences between generating capability and generating capacity may be caused by a number of factors. These include the water levels in reservoirs, the fact that not all equipment can be placed on line at the same time, and the fact that some equipment may be out of service for one reason or another.

RESERVE MARGINS

The reserve margin of an electrical system is defined as the excess of net generating capability for in-province use over the in-province firm peak that occurred during the year, expressed as a percentage of in-province firm peak. Column 4 of Table 6.7 presents the reserve margin in the provinces and territories in 1987. Newfoundland had the largest reserve with 91 per cent, followed by the Yukon with 78 per cent, the Northwest Territories with 68 per cent, Prince Edward Island with 54 per cent, and British Columbia with 51 per cent. The reserve margin for Canada as a whole was 32 per cent.

Table 6.8 summarizes reserve margin percentages for the period 1960-87. In general, margins have steadily increased since 1960.

Table 6.6. Commercial nuclear power plants in Canada, 1987

	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	759	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	759	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	835	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	837	1986
18	Bruce B8	Ontario	837	1987

Source: Uranium and Nuclear Energy Branch, Energy, Mines and Resources Canada.

Table 6.7. Surplus capacity, 1987

	Net Generating Capability for In-Province Use (MW) (1)	In-Province Firm peak (MW) (2)	Reserve Margin (MW) (3) = (1)-(2)	Percentage of Reserve (4) = (3)/(2)
Newfoundland	2 995	1 570	1 425	91
P.E.I.	140	91	49	54
Nova Scotia	2 019	1 445	574	40
New Brunswick	3 040	2 210	830	38
Quebec	31 266	25 885	5 381	21
Ontario	27 915	21 442	6 473	30
Manitoba	4 286	2 992	1 294	43
Saskatchewan	2 694	2 126	568	27
Alberta	7 387	5 207	2 180	42
B.C.	12 499	8 271	4 228	51
Yukon	121	68	53	78
N.W.T.	186	111	75	68
Canada	94 532	71 418	23 114	32

Source: Electric Power Statistics, Volume I, *Statistics Canada, Catalogue 57-204.*

Table 6.8. Surplus capacity percentages, 1960-1987

	1960	1965	1970	1975	1980	1985	1986	1987
				(per cent)				
Nfld.	20	17	55	48	98	101	79	91
P.E.I.	81	66	33	33	13	40	42	54
N.S.	39	32	13	18	62	38	38	40
N.B.	17	9	49	34	33	51	41	38
Que.	37	16	16	10	14	20	20	21
Ont.	14	6	13	26	34	11	12	30
Man.	32	41	24	18	54	48	47	43
Sask.	60	28	26	30	7	15	26	27
Alta.	30	23	38	32	45	36	46	42
B.C.	43	19	23	30	49	50	60	51
Yukon	42	100	23	58	29	130	72	78
N.W.T.	87	48	42	46	51	70	85	68
Canada	28	15	19	25	31	26	30	32

Source: Calculated from Electric Power Statistics, Volume I, *Statistics Canada, Catalogue 57-204.*

7. Electricity Trade

INTERNATIONAL TRADE

Electricity trade between Canada and the United States dates back to the beginning of the century. In 1901, the first electric power transmission line (12 000 volts) was built across the border at Niagara Falls. This early interconnection enabled Canada to market its abundant hydroelectric power in the United States. For most of the century, electricity trade between Canada and the United States was balanced. However, between the early 1970s and 1987, Canada's net exports to the United States grew steadily in both quantity and revenue. Electricity trade statistics for the period 1960-87 are summarized in Table 7.1.

In 1987, electricity exports to the United States (excluding non-cash service exchanges) were 45 359 GW.h, an increase of 29 per cent from 1986. The higher export volumes are mainly attributable to increased sales by B.C. Hydro and new sales by Hydro-Québec to the New England area. Electricity exports in 1987 accounted for 9.4 per cent of Canada's total generation, up from 7.7 per cent in 1986.

Export revenues increased 12 per cent in 1987 to $1.211 billion, compared to $1.086 billion in 1986. Electricity imports from the United States in 1987 were 536 GW.h, and import costs to Canada were about

Table 7.1. Canada-U.S. electricity trade, 1960-1987

	Exports* (GW.h) (1)	Exports as a percentage of net generation (2)	Export revenues ($ million) (3)	Imports* (GW.h) (4)	Imports as a percentage of total disposal (5)	Import costs ($ million) (6)	Net Exports GW.h (7)=(1)-(4)	Net Exports $ Million (8)=(3)-(6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1961	4 158	3.7	10	1 394	1.3	2	2 764	8
1962	4 112	3.5	8	2 779	2.4	3	1 333	5
1963	3 613	3.0	7	2 884	2.4	3	729	4
1964	4 159	3.1	10	3 121	2.3	3	1 038	7
1965	3 684	2.6	8	3 575	2.5	3	109	5
1966	4 397	2.8	8	3 218	2.1	3	1 179	5
1967	3 994	2.4	8	4 181	2.6	6	-187	2
1968	3 988	2.1	8	4 129	2.3	6	-141	2
1969	4 320	2.3	15	2 740	1.5	3	1 580	12
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1971	7 321	3.4	45	3 378	1.6	8	3 943	37
1972	11 037	4.6	66	2 381	1.0	3	8 656	63
1973	16 286	6.2	115	2 249	0.9	1	14 037	114
1974	15 400	5.5	169	2 441	0.9	1	12 959	168
1975	11 409	4.2	105	3 972	1.5	3	7 819	102
1976	12 804	4.4	174	3 590	1.3	7	9 214	167
1977	19 957	6.3	419	2 690	0.9	13	17 267	406
1978	20 437	6.1	479	170	0.1	2	20 267	477
1979	30 458	8.6	739	24	0.0	1	30 434	738
1980	28 224	7.7	794	168	0.1	3	28 056	791
1981	34 730	9.1	1 144	466	0.1	5	34 264	1 138
1982	32 986	8.8	1 107	257	0.1	5	32 729	1 102
1983	37 258	9.4	1 249	239	0.1	6	37 019	1 243
1984	37 563	8.8	1 355	290	0.1	10	37 272	1 345
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1986	35 271	7.7	1 086	343	0.1	9	34 928	1 077
1987	45 359	9.4	1 211	536	0.1	12	44 823	1 199

* *Exports and imports prior to 1977 include service exchanges.*

Source: Electric Power Statistics, Volume II, *Catalogue 57-202, Statistics Canada. Energy, Mines and Resources Canada.*

$12 million, up slightly from the previous year.

Electricity exports to the United States by type of energy transaction during the period 1960-87 are presented in Table 7.2. In the past 28 years, firm exports[1] fluctuated between 14 and 31 per cent, and interruptible exports[2] ranged from 69 to 86 per cent. In 1987, approximately 81 per cent of the electricity exported was interruptible, up from 72 per cent in 1986. The revenue share of interruptible exports was 71 per cent in 1987, compared with 56 per cent in 1985.

Average export revenues for the period 1960-87 are reported in Table 7.3. The table illustrates the fact that firm exports are normally more valuable than interruptible exports. This has been the case in all years except 1974-75 and 1979-81.

Table 7.2. Electricity exports to the United States by type, 1960-1987

	Quantity (GW.h)		Revenue ($1000)		Quantity share (%)		Revenue share (%)	
	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1961	1 192	2 965	5 769	3 783	29	71	60	40
1962	1 261	2 851	6 487	1 775	31	69	79	21
1963	882	2 730	4 625	2 028	24	76	70	30
1964	871	3 289	5 561	4 359	21	79	56	44
1965	635	3 049	4 261	3 322	17	83	56	44
1966	614	3 783	4 257	3 402	14	86	56	44
1967	705	3 289	4 663	3 068	18	82	60	40
1968	741	3 247	5 003	2 714	19	81	65	35
1969	838	3 482	5 735	9 279	19	81	38	62
1970	984	4 648	6 828	25 309	18	82	21	79
1971	1 860	5 461	13 270	31 951	25	75	29	71
1972	2 047	8 990	19 198	46 846	19	81	29	71
1973	2 637	13 649	19 891	94 947	16	84	17	83
1974	2 488	12 912	20 939	147 945	16	84	12	88
1975	2 375	9 034	20 382	84 488	21	79	19	81
1976	2 061	10 743	39 010	134 755	16	84	22	78
1977	3 727	16 230	90 220	329 050	19	81	22	78
1978	3 980	16 457	94 543	384 011	20	80	20	80
1979	6 692	23 766	135 763	602 740	22	78	18	82
1980	7 232	20 992	156 731	636 760	26	74	20	80
1981	5 008	29 722	105 116	1 038 761	14	86	9	91
1982	5 831	27 154	243 140	863 558	18	82	22	78
1983	10 569	26 689	445 751	802 806	28	72	36	64
1984	10 852	26 711	491 662	863 057	29	71	36	64
1985	12 305	29 136	547 109	877 657	30	70	38	62
1986	9 756	25 515	480 767	605 258	28	72	44	56
1987	8 840	36 519	354 781	856 068	19	81	29	71

Source: Electric Power Statistics, Volume II, *Catalogue 57-202, Statistics Canada. Energy, Mines and Resources Canada.*

[1] In firm export transactions, the exporting utility guarantees the delivery of energy or capacity over a scheduled period of time.

[2] Interruptible export transactions are sales of energy and/or power from surplus generating resources. There is no guarantee of delivery and interruptible exports can be curtailed by the seller on very short notice.

Average firm export revenues dropped 19 per cent to 40.1 mills per kW.h in 1987, from 49.3 mills per kW.h in 1986. Average interruptible export revenues declined by 1.3 per cent, from 23.7 mills per kW.h in 1986 to 23.4 mills per kW.h in 1987.

Table 7.4 summarizes the generating sources of electricity exports to the United States during the period 1975-87. Hydro-generated electricity continued to be the main source of Canada's electricity exports, accounting for more than 75 per cent of the total exported in 1987, up from 73 per cent in 1986.

Provincial sources of exports, revenues, and average revenues received in 1986 and 1987 are reported in Table 7.5. Quebec, Ontario, and British Columbia showed increases in the quantity of electricity exported in 1987, while Manitoba, Saskatchewan, and New Brunswick showed decreases. The largest decrease occurred in Manitoba, as a result of low water conditions in the province.

The average revenue received from electricity exports in 1987 varied significantly from province to province. New Brunswick received

Table 7.3. Average export revenues, 1960-1987

Year	Firm	Interruptible	Total
	(mills/kW.h)		
1960	4.2	2.3	2.6
1961	4.8	1.3	2.3
1962	5.1	0.6	2.0
1963	5.2	0.7	1.8
1964	6.4	0.9	2.4
1965	6.7	1.1	2.1
1966	6.9	0.9	1.7
1967	6.6	0.9	1.9
1968	6.8	0.8	1.9
1969	6.8	2.7	3.5
1970	6.9	5.5	5.7
1971	7.1	5.9	6.2
1972	9.4	5.2	6.0
1973	7.5	7.0	7.1
1974	8.4	11.5	11.0
1975	8.6	9.4	9.2
1976	18.9	12.5	13.6
1977	24.2	20.3	21.0
1978	23.8	23.3	23.4
1979	20.3	25.4	24.3
1980	21.7	30.3	28.1
1981	21.0	34.9	32.9
1982	41.7	31.8	33.6
1983	42.2	30.1	33.5
1984	45.3	32.3	36.1
1985	44.5	30.1	34.4
1986	49.3	23.7	30.8
1987	40.1	23.4	26.7

Source: Calculated from Electric Power in Canada, 1987, *Table 7.2.*

Table 7.4. Generation sources of Canadian exports, 1975-1987

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Total
1975	5 724	4 838	494	353	0	11 409
1976	6 973	4 323	1 206	302	0	12 804
1977	7 926	8 514	2 961	555	0	19 957
1978	7 290	10 476	2 260	411	0	20 437
1979	15 213	11 587	3 354	128	177	30 458
1980	14 135	10 599	2 867	593	30	28 224
1981	21 182	10 901	1 940	665	42	34 730
1982	20 114	10 315	1 959	502	96	32 986
1983	21 978	11 704	1 201	519	1 856	37 258
1984	22 807	10 582	1 552	711	1 911	37 563
1985	28 836	8 245	1 157	956	2 247	41 441
1986	25 727	5 389	846	825	2 484	35 271
1987	34 065	7 575	1 270	408	2 041	45 359

Source: Compiled from National Energy Board statistics.

Table 7.5. Electricity exports and revenues by province, 1986-1987*

	Quantity (GW.h)			Revenue (million $)			Average Revenue (mills/kW.h)		
	1986	1987	% Change	1986	1987	% Change	1986	1987	% Change
N.B.	6 652	5 910	11	278.8	278.0	0	47.9	47.1	12
Que.	12 640	16 400	30	378.3	445.4	18	29.9	27.2	-9
Ont.	6 757	7 194	7	270.3	215.6	-20	40.0	30.0	-25
Man.	7 009	3 314	-53	111.7	65.3	-42	16.0	19.7	23
Sask.	110	55	-50	1.1	0.2	-82	10.6	3.1	-71
B.C.	2 103	12 486	494	45.5	206.4	254	21.7	16.5	-24
Canada	35 271	45 359	29	1 086.0	1 210.9	12	30.8	26.7	-13

* *Excludes non-cash exchanges.*

Source: National Energy Board.

the highest average revenue, 47.1 mills per kW.h, while Saskatchewan received the lowest, 3.1 mills per kW.h. This variance reflects differences in the product exported, the cost of generation, and the alternatives available in the export market.

As indicated in Table 7.5, average revenues for most of the exporting provinces fell in 1987. The low international price of crude oil was the main factor contributing to lower average revenues. As mentioned above, more than 81 per cent of electricity exports to the United States in 1987 were interruptible sales, which are largely priced in relation to the importing utility's marginal cost of oil-fired generation. Lower world oil prices mean lower U.S. generation costs which, in turn, reduce Canada's export prices. For Canada as a whole, average export revenue dropped by 13 per cent in 1987.

Table 7.6 presents the proportion of firm and interruptible electricity exports for the six exporting provinces. While firm exports accounted for just 19 per cent of total Canadian electricity exports in 1987, the proportion of firm exports

Table 7.6. Firm and interruptible exports, 1987*

	Firm	Interruptible	Firm	Interruptible
	(GW.h)		(per cent)	
New Brunswick	2 319	3 590	39	61
Quebec	5 264	11 137	32	68
Ontario	265	6 929	4	96
Manitoba	501	2 813	15	85
Saskatchewan	44	11	80	20
British Columbia	447	12 039	4	96
Canada	8 840	36 519	19	81

* *Exchanges are excluded.*

Source: National Energy Board.

Table 7.7. Energy sources of electricity exports, 1987

	Oil	Coal	Nuclear	Hydro	Total
			(per cent)		
New Brunswick	22.5	11.0	34.3	32.2	100
Quebec	-	-	-	100.0	100
Ontario	-	98.3	1.0	0.7	100
Manitoba	-	17.5	-	82.5	100
Saskatchewan	-	100.0	-	-	100
British Columbia	-	-	-	100.0	100
Canada	2.8	16.7	4.5	75.1	100

Source: Energy, Mines and Resources Canada.

ranged from 4 per cent in Ontario and British Columbia, to about 80 per cent in Saskatchewan.

Table 7.7 reports the provincial energy sources of electricity exported during 1987. Exports from Quebec and British Columbia were generated entirely from hydroelectric stations. Manitoba's exports also overwhelmingly came from hydro. Exports from Saskatchewan were generated entirely from indigenous coal, while Ontario's exports came primarily from thermal stations using imported coal. Nuclear-generated power for export decreased in Ontario, from 2.5 per cent in 1986 to 1.0 per cent in 1987. In New Brunswick, electricity exports were generated from nuclear, oil, and coal sources. The hydro-based electricity exported by New Brunswick was purchased from Quebec and not generated within the province. New Brunswick was the only province using base-load oil-fired generation for exports.

Export markets in the U.S. are summarized in Table 7.8. New York State was the most important market for Canadian electricity exports. Of the total 45 359 GW.h exported in 1987, New York received about 15 832 GW.h, or 35 per cent. New York accounted for 35 per cent of Canada's total $1.211 billion export revenue.

The New England states were also an important market for Canadian electricity exports in 1987. They imported 12 861 GW.h from New Brunswick, Quebec, and Ontario, accounting for 28 per cent of total Canadian electricity exports. New England contributed $495 million, or 41 per cent of Canada's total export revenue.

Canadian electricity exports, as a percentage of total electrical energy demand in the United States, increased from 1.4 per cent in 1986 to 1.8 per cent in 1987. However, the dependence of the U.S. on Canadian exports was higher in certain regions. Exports to New York accounted for 12 per cent of the state's total electricity consumption in 1987. The corresponding ratio was 13 per cent for New England, 3 per cent for the Midwest, and 3 per cent for the Pacific Northwest and California.

Provincial shares of total Canadian electricity exports are shown in Table 7.9. Quebec was the leading exporter in 1987, followed by British Columbia and Ontario.

Table 7.8. Exporting provinces and importing markets, 1987

Exporting Province	Importing Market	Quantity (MW.h)	Value ($1000)
New Brunswick	Maine	4 096 147	157 602
	Massachusetts	1 813 437	120 432
Quebec	Maine	947	47
	New Hampshire	17	1
	Vermont	1 914 164	70 648
	New England	4 772 999	136 241
	New York	9 712 113	238 409
Ontario	New York	6 119 645	182 594
	Michigan	808 226	22 459
	Minnesota	2 850	118
	Vermont	263 524	10 400
Manitoba	Minnesota	2 561 070	50 966
	North Dakota	753 052	14 342
Saskatchewan	North Dakota	54 960	168
British Columbia	Washington	1 681 905	30 295
	Oregon	4 656 834	65 663
	Idaho	41 132	681
	Montana	28 083	405
	California	6 020 559	108 517
	Nevada	19 539	277
	Utah	37 146	520
	Alaska	423	63
Canada	United States	45 358 776	1 210 848

Source: National Energy Board.

ELECTRICITY TRADE AND THE ECONOMY

The export of electricity is an important aspect of Canada's foreign trade. Although total electricity export revenue accounted for only 1.0 per cent of total merchandise exports in 1987, Figure 7.1 shows that net electricity export revenue contributed 13 per cent of the total $8.97 billion merchandise trade balance in the same year.

Canadian energy trade by fuel type during the period 1978-87 is reported in Table 7.10. In 1987, total electricity export revenue

Table 7.9. Provincial shares of Canadian electricity exports, 1960-1987

Year	New Brunswick	Quebec	Ontario	Manitoba	Saskatchewan	British Columbia	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1961	4.9	9.8	84.8	0.0	0.0	0.5	100.0
1962	6.0	7.2	86.4	0.0	0.0	0.4	100.0
1963	6.8	0.7	91.8	0.0	0.0	0.7	100.0
1964	5.9	1.1	92.3	0.0	0.0	0.7	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1966	7.1	0.6	73.8	0.0	0.0	18.5	100.0
1967	8.4	0.6	77.7	0.0	0.0	13.3	100.0
1968	9.7	0.9	63.4	0.0	0.0	26.0	100.0
1969	11.2	0.7	66.7	0.0	0.0	21.4	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1971	18.2	0.9	55.5	9.4	0.0	16.0	100.0
1972	17.0	0.8	55.0	7.7	0.0	19.5	100.0
1973	17.5	0.4	47.0	6.1	0.0	29.0	100.0
1974	16.2	5.7	51.1	8.8	0.0	18.2	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1976	19.3	4.1	48.6	5.6	0.0	22.4	100.0
1977	17.8	2.9	48.3	2.9	0.0	28.1	100.0
1978	12.4	6.9	52.7	15.0	0.0	13.0	100.0
1979	12.9	25.4	40.2	13.4	0.0	8.4	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1981	9.3	24.0	33.2	10.3	0.0	23.2	100.0
1982	9.1	25.9	33.8	15.8	0.1	15.3	100.0
1983	14.2	27.5	33.9	16.0	0.2	8.2	100.0
1984	15.1	29.9	29.4	13.6	0.2	11.8	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1986	18.9	35.8	19.1	19.9	0.3	6.0	100.0
1987	13.0	36.2	15.9	7.3	0.1	27.5	100.0

Source: Energy, Mines and Resources Canada.

accounted for about 9 per cent of total energy export revenue. In terms of net revenue, however, electricity accounted for 16 per cent, as shown in Figure 7.2.

INTERPROVINCIAL TRADE

Annual Canadian interprovincial electricity trade for the period 1960-87 is summarized in Table 7.11. When the Churchill Falls hydro project began producing electricity in 1972, the volume of interprovincial electricity trade increased substantially because Newfoundland sold almost all of the output to Quebec under contract. Interprovincial electricity trade reached a peak in 1975, accounting for about 18 per cent of total Canadian generation; the percentage has declined gradually since then. By 1987, interprovincial electricity trade accounted for 10.2 per cent of total production, down from 11.1 per cent in 1986.

Interprovincial transfers during the period 1978-87 are summarized in Table 7.12. More information on exports and imports by province is provided in Figure 7.3 and Table A5 in Appendix A.

Table 7.10. Canadian energy trade, 1978-1987

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			(millions of dollars)			
1978						
Exports	2 568	2 190	704	479	207	6 599
Imports	3 767	0	712	2	12	4 493
Balance	-1 199	2 190	-8	477	195	2 106
1979						
Exports	4 265	2 889	750	729	379	9 614
Imports	4 798	3	934	1	12	5 748
Balance	-533	2 886	-184	728	367	3 866
1980						
Exports	4 891	3 984	824	773	231	11 328
Imports	7 487	0	885	2	17	8 391
Balance	-2 596	3 984	-61	771	214	2 937
1981						
Exports	5 228	4 370	1 065	1 123	178	12 636
Imports	8 627	0	928	6	15	9 576
Balance	-3 399	4 370	137	1 117	163	3 060
1982						
Exports	5 218	4 755	1 203	1 120	359	13 089
Imports	5 763	1	1 017	5	17	6 793
Balance	-545	4 754	186	1 115	342	6 296

Table 7.10. Canadian energy trade, 1978-1987 (Continued)

	Oil	Natural Gas	Coal	Electricity	Uranium	Total Energy
			(millions of dollars)			
1983						
Exports	6 338	3 958	1 247	1 228	63	13 201
Imports	4 221	1	941	3	15	5 180
Balance	2 117	3 957	306	1 225	48	8 020
1984						
Exports	7 580	3 886	1 851	1 379	334	15 718
Imports	4 919	0	1 203	13	15	6 150
Balance	2 661	3 886	648	1 366	319	9 421
1985						
Exports	9 239	3 912	2 030	1 408	232	17 411
Imports	5 242	0	1 023	8	28	6 301
Balance	3 997	3 912	1 007	1 400	204	11 110
1986						
Exports	5 854	2 483	1 869	1 080	842	12 128
Imports	3 082	0	874	9	31	5 293
Balance	2 772	2 483	995	1 071	811	6 835
1987						
Exports	8 029	2 527	1 696	1 211	886	13 349
Imports	4 810	0	844	12	18	5 683
Balance	3 219	2 527	852	1 199	868	7 666

Source: Statistics Canada, Exports by Commodities *(65-004) and* Imports by Commodities *(65-007).*

Table 7.11. Annual Canadian interprovincial electricity trade, 1960-1987

Year	Total Canadian Generation (GW.h)	Delivered to other Provinces (GW.h) With Churchill Falls	Delivered to other Provinces (GW.h) Without Churchill Falls	Percentage of Interprovincial Transfers to Total Generation With Churchill Falls	Percentage of Interprovincial Transfers to Total Generation Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1961	113 713	7 411	7 411	6.5	6.5
1962	117 469	7 188	7 188	6.1	6.1
1963	122 238	6 586	6 586	5.4	5.4
1964	134 987	8 241	8 241	6.1	6.1
1965	144 274	6 230	6 230	4.3	4.3
1966	158 135	7 771	7 771	4.9	4.9
1967	165 625	6 874	6 874	4.2	4.2
1968	176 378	6 578	6 578	3.7	3.7
1969	191 102	6 338	6 338	3.3	3.3
1970	204 723	8 137	8 137	4.0	4.0
1971	216 472	8 047	7 870	3.7	3.6
1972	240 213	17 787	11 470	7.4	4.8
1973	263 335	28 933	15 129	11.0	5.8
1974	279 915	40 768	18 624	14.6	6.7
1975	273 392	49 198	19 684	18.0	7.2
1976	294 043	51 931	19 909	17.7	6.8
1977	316 940	52 005	18 739	16.4	5.9
1978	335 946	53 645	16 706	16.0	5.0
1979	353 051	49 847	14 642	14.1	4.2
1980	367 306	52 709	14 965	14.4	4.1
1981	380 131	51 181	15 325	13.5	4.0
1982	376 805	50 303	14 609	13.4	3.9
1983	395 850	46 007	14 863	11.6	3.8
1984	425 414	53 302	17 375	12.5	4.1
1985	446 413	51 663	19 917	11.6	4.5
1986	455 795	50 706	20 102	11.1	4.4
1987	482 108	49 201	18 808	10.2	3.9

Source: Energy, Mines and Resources Canada.

Figure 7.1. Net electricity exports and Canadian merchandise trade balance, 1987

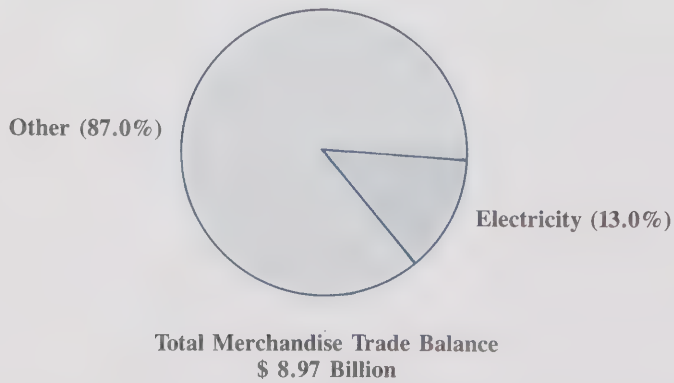
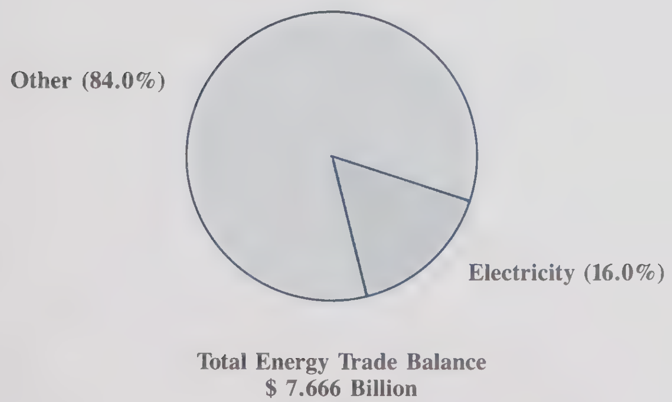


Table 7.12. Interprovincial electricity trade by destination, 1978-1987

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
					(GW.h)					
Newfoundland to Quebec	37 024	35 290	37 829	35 941	35 779	31 229	36 012	31 836	30 695	30 393
Nova Scotia to New Brunswick	40	151	226	112	133	121	271	190	71	82
New Brunswick to Nova Scotia	264	494	172	303	217	737	303	360	620	659
New Brunswick to P.E.I.	270	362	392	481	478	520	550	585	610	483
New Brunswick to Quebec	0	0	0	0	0	1	0	2	0	20
Quebec to New Brunswick	3 546	3 588	3 675	3 717	3 615	3 971	4 342	5 951	7 204	6 840
Quebec to Ontario	8 661	5 389	5 567	6 494	5 768	5 378	7 364	8 685	7 292	5 942
Ontario to Quebec	456	204	50	58	57	52	68	106	17	15
Ontario to Manitoba	2	23	0	0	3	13	2	0	5	3
Manitoba to Ontario	1 257	1 827	1 575	1 164	1 066	955	940	959	735	1 050
Manitoba to Saskatchewan	790	1 248	1 579	1 305	1 488	1 610	1 593	1 530	1 211	1 262
Saskatchewan to Manitoba	828	774	951	1 054	1 066	1 209	1 299	1 240	1 076	1 220
Saskatchewan to Alberta	0	0	4	3	3	2	3	0	0	0
Alberta to Saskatchewan	0	0	0	0	0	4	0	0	0	0
Alberta to B.C.	280	394	385	261	188	46	259	182	617	710
B.C. to Alberta	227	103	100	165	442	163	296	37	553	521
Total	53 645	49 847	52 709	51 181	50 303	46 007	54 302	51 663	50 706	49 201

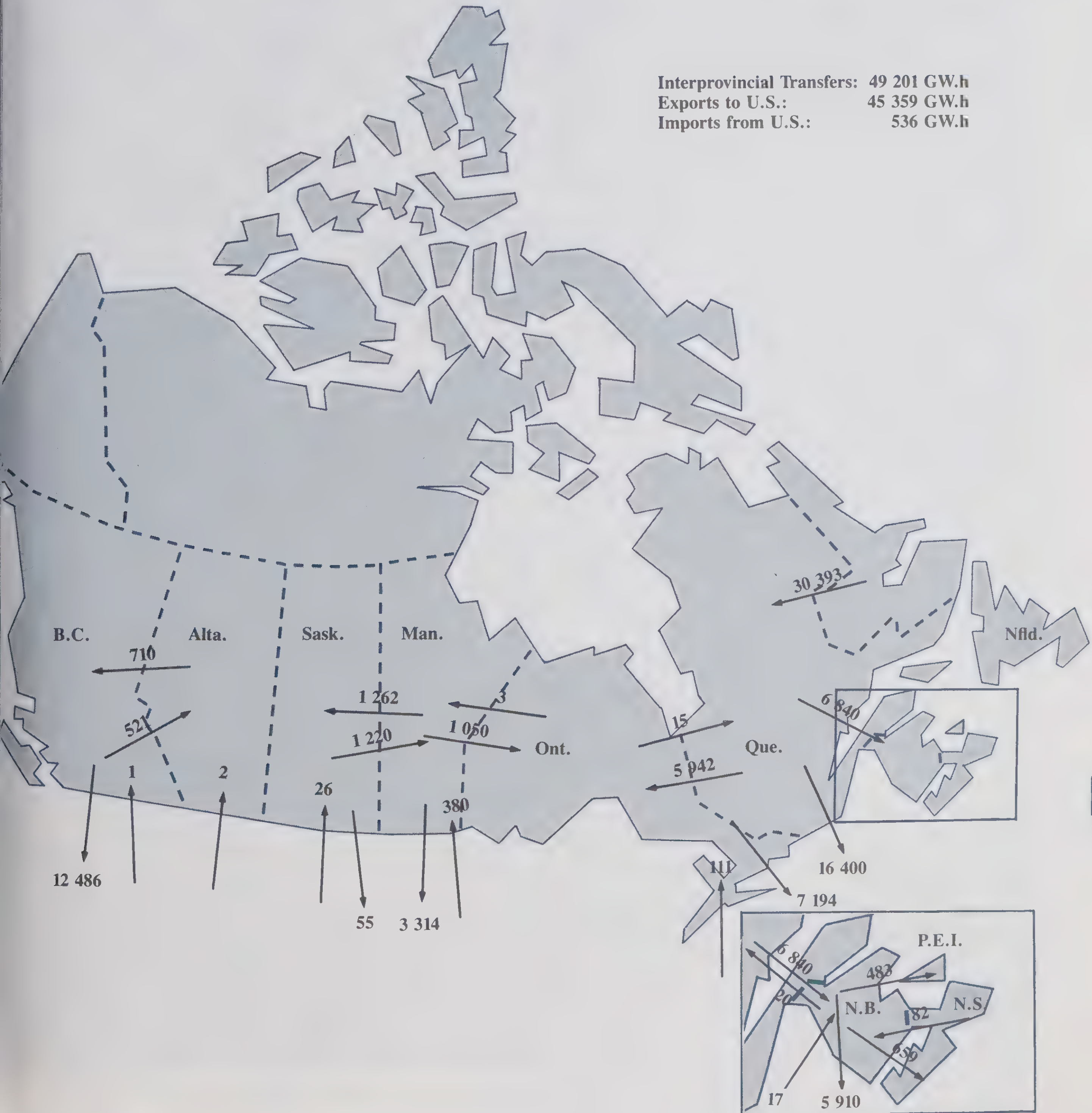
Source: Energy, Mines and Resources Canada.

Figure 7.2. Net electricity exports and Canadian energy trade balance, 1987



An Alberta Power employee makes repairs to one of the company's lines near Vegreville, Alberta.

Figure 7.3. Electricity trade, 1987 (GW.h)



A 500-kV tower goes up at Edmonton Power's coal-fired Genesee generating station. Genesee will add 400 MW to the Alberta Interconnected System when it comes on line in late 1989.

8. Transmission

Total circuit length of electrical transmission in Canada, for lines rated at 50 kV and above, increased by 853 km in 1987. The total distance of Canadian transmission is now 147 756 km. The largest share of it (32 per cent) is in the 100 kV to 149 kV range. Another 25 per cent is in the 200 kV to 299 kV range, while 21 per cent is between 50 kV and 99 kV. Newfoundland and Quebec are the only two provinces with transmission lines over 600 kV; their circuit length is 10 520 km, about 7 per cent of the Canadian total. Quebec has the greatest amount of electrical transmission, with 34 567 km, or 23 per cent of Canada's total. It is followed by Ontario with 19 per cent, and Alberta and Manitoba with 12 per cent each.

Transmission circuit length by province and voltage is reported in Table 8.1.

The additions in 1987 were mainly in Manitoba, Alberta, Quebec, and Newfoundland. The Alberta Interconnected System increased its 240-kV lines by 222 km. Manitoba Hydro extended its 138-kV line by 270 km. Newfoundland and Labrador Hydro increased its system by 105 km with the addition of one 138-kV line. Other minor additions to transmission lines within the provinces occurred in Prince Edward Island, New Brunswick, and Quebec.

There are several transmission lines now under construction. Ontario is in the process of adding three 500-kV lines, with two scheduled to be completed in 1988 and the third in 1989. The new lines will increase Ontario's total circuit length by 448 km. In Saskatchewan, a 138-kV line is under construction and is expected to increase the province's transmission system by 355 km. A 230-kV line with a circuit length of 123 km is also under construction in Manitoba.

INTERPROVINCIAL TRANSMISSION

Table 8.2 presents the major provincial interconnections. Currently, there are 32 interties, with a total design capability of 9895 MW. Although there were no additions to interprovincial

Table 8.1. Transmission circuit length in Canada, 1987

	50 - 99 kV	100 - 149 kV	150 - 199 kV	200 - 299 kV	300 - 399 kV	400 - 599 kV	600 kV and up	Total
Nfld.	2 211	1 827	-	2 005	-	-	612	6 655
P.E.I.	371	173	-	-	-	-	-	544
N.S.	2 132	1 703	-	1 150	173	-	-	5 158
N.B.	2 776	1 897	-	528	1 057	-	-	6 258
Que.	4 251	7 534	2 180	3 671	7 023	-	9 908	34 567
Ont.	291	12 305	-	13 461	6	2 233	-	28 296
Man.	6 690	4 526	-	4 157	-	2 042	-	17 415
Sask.	4 820	3 702	-	2 629	-	-	-	11 151
Alta.	3 458	8 571	159	5 225	-	356	-	17 715
B.C.	4 799	4 235	264	3 759	403	5 344	-	13 460
Yukon	64	497	-	-	-	-	-	561
N.W.T.	129	503	-	-	-	-	-	632
Canada	31 992 (21%)	47 419 (32%)	2 603 (2%)	36 585 (25%)	8 662 (6%)	9 975 (7%)	10 520 (7%)	147 756 (100%)

Source: Statistics Canada publication 57-202.
Energy, Mines and Resources Canada.

interconnections in 1987, Manitoba began construction of a 115-kV line to replace an existing one that runs from the Seven Sisters generating station in Manitoba to Kenora, Ontario. The new line will have a total circuit length of 81 km. One important interconnection was proposed in 1987. SaskPower and Alberta Power Ltd. signed an agreement to jointly construct a $41-million high-voltage-direct-current (HVDC) interconnection linking the electrical systems of the two provinces. This interconnection will run from Swift Current, Saskatchewan, to Empress, Alberta, and will enable Alberta and Saskatchewan to share 100 MW of generation resources and allow electric power sales between the two provinces. The interconnection will involve 175 km of 230-kV transmission line in Saskatchewan and 10 km of 138-kV line in Alberta. It will be the first Canadian link between the eastern and western power systems of North America. Construction of the interconnection, which is subject to regulatory approval in both provinces, is scheduled to begin in mid-1988 and be completed late the following year.

Table 8.2. Provincial interconnections at year end, 1987

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 × 500	800
	1 × 138	110
Saskatchewan - Manitoba	3 × 230	400
Manitoba - Ontario	2 × 230	260
	1 × 115	
Ontario - Quebec	4 × 230	1 300
	7 × 120	
Quebec - Newfoundland	3 × 735	5 225
Quebec - New Brunswick	2 × ±80 (DC)	700
	2 × 345	
	2 × 230	300
New Brunswick - Nova Scotia	2 × 138	600
	1 × 345	
New Brunswick - P.E.I.	1 × 138	200

** Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

INTERNATIONAL TRANSMISSION

There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 36 bulk power interties rated at 69 kV or higher, with a total power transfer capacity of 13 500 MW. These are presented in Table 8.3.

LONG-DISTANCE TRANSMISSION

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls, to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of the major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 700-kV class transmission system. This system now extends over 1100 km from the Churchill Falls development in Labrador to Montreal; a comparable system of about the same distance extends from the James Bay development to Quebec's load centres.

In Manitoba, pioneering work was done to develop the ±450-kV HVDC system, which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Ontario and British Columbia also have extensive EHV systems in the 500-kV class. All of these systems are shown in Figure 8.1.

Such advances in Canadian transmission techniques have provided not only for long-distance

Table 8.3. Major interconnections between Canada and the United States*

Province	State	Voltage (kV)	Design Capability*** (MW)
New Brunswick	*Maine*	1 × 345	600
		1 × 138	60
		5 × 69	155
Quebec	*New York*	1 × 765	1 400
	New York	2 × 120	200
	Vermont	2 × 120	200
	New Hampshire	± 450(DC)	690
*Ontario***	*New York*	1 × 230	470
		1 × 230	400
		2 × 230	600
		2 × 345	2 300
		2 × 69	132
		2 × 115	200
	Michigan	1 × 230	535
		1 × 230	515
		2 × 345	1 470
	Minnesota	1 × 120	35
Manitoba	*North Dakota*	1 × 230	150
	Minnesota	1 × 230	175
	Minnesota	1 × 500	1 000
Saskatchewan	*North Dakota*	1 × 230	150
British Columbia	*Washington*	1 × 230	350
		1 × 230	300
		2 × 500	1 400

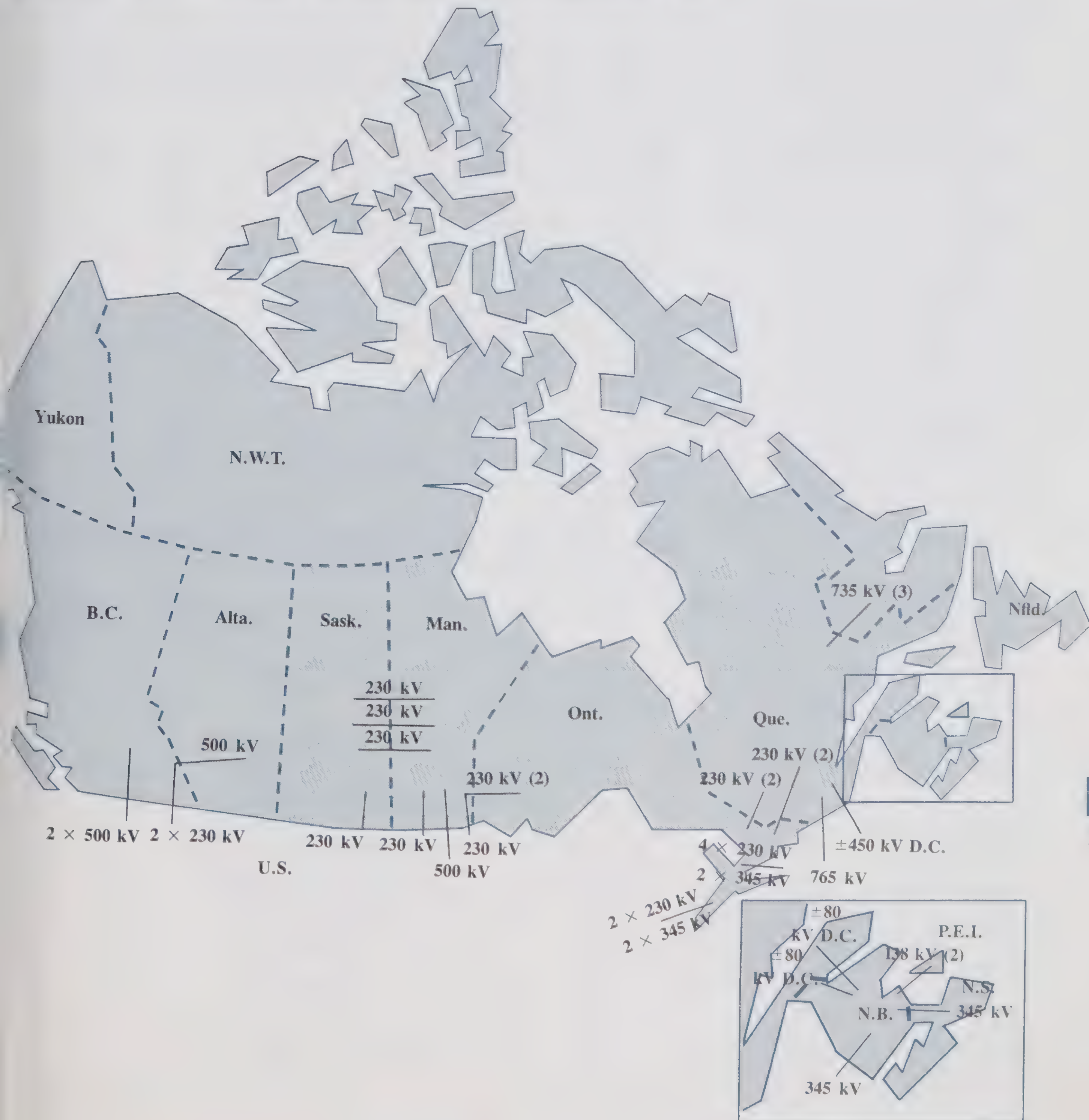
* *35 MW capacity or over.*
** *The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.*
*** *Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

bulk transmission, but also for extensive interconnections between neighbouring provinces (32 interties) and between Canada and the United States (over 100 interties). Figure 8.2 indicates the major provincial and international interconnections.

Figure 8.1. Canada's major long-distance transmission systems, 1987

Figure 8.2. Major provincial and international interconnections, 1987



9. Electric Utility Investment and Financing

CAPITAL INVESTMENT

Every year, electric utilities make investments in new facilities or upgrade old facilities to meet their customers' needs. Between 1971 and 1987, electric utility capital investment increased from \$1.8 billion to \$6.2 billion, with an average annual growth rate of 8.3 per cent. Table 9.1 illustrates the capital-intensive nature of electricity and its importance in the Canadian economy. Before 1980, electric utility investment in Canada was more than 50 per cent of total investment in the energy sector. This share reached a peak of 58 per cent in 1978 and then gradually declined, reflecting surplus capacity in the industry. However, the investment share of the electrical industry has increased significantly in the past two years. Electric utility capital investment accounted for 47 per cent of the total investment in the energy sector in 1987, as compared with 41 per cent in 1986 and only 34 per cent in 1985.

Electric utility investment in Canada, as a share of both total investment in the economy and GDP, has declined since 1982. In 1978, the investment share of the electric power industry accounted for 11 per cent of total investment in the economy, and 2.5 per cent of GDP. These shares dropped to 5 per cent and 1.1 per cent respectively in 1987.

Table 9.2 summarizes capital expenditures in the energy sector. During the period 1971-87, the electric power industry had the largest investment share in the energy sector, with the exception of 1984 and 1985, when crude oil and natural gas had the largest share.

Of the \$6.2 billion capital investment in 1987, about 46 per cent was for generation, 20 per cent for transmission, and 19 per cent for distribution. Figure 9.1 shows

Table 9.1. Electric utility capital investment, 1971-1987

	Investment in electric power industry (\$ million)	As a percentage of total energy investment	As a percentage of total investment in the economy	As a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 729	34	6	1.2
1986	5 618	41	6	1.1
1987	6 233	47	5	1.1

Source: Energy, Mines and Resources Canada.

Figure 9.1. Capital investment by function, 1987

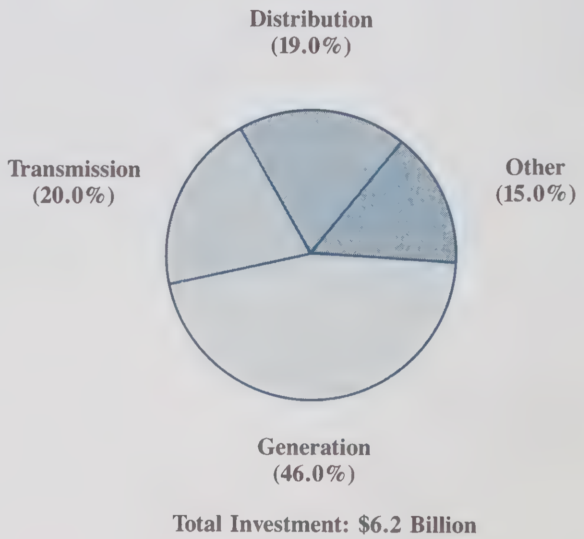


Table 9.2. Investment in energy-related industries, 1971-1987

Year	Crude oil and natural gas	Refined petroleum and coal products	Natural gas distribution	Electric power	Coal mines	Uranium mines	Other*	Total
				(millions of dollars)				
1971	463	231	115	1 747	90	6	702	3 381
1972	666	244	142	1 754	37	11	683	3 567
1973	824	319	146	2 244	39	18	589	4 220
1974	1 088	430	192	2 753	88	35	546	5 151
1975	1 390	450	193	3 957	121	30	662	6 831
1976	1 868	344	182	4 229	191	66	666	7 676
1977	2 251	367	213	4 884	248	113	666	8 782
1978	2 271	315	247	5 936	219	180	745	10 258
1979	3 886	274	263	6 364	214	243	793	12 037
1980	5 745	325	386	6 109	299	277	1 317	14 458
1981	6 445	848	409	7 319	576	289	2 285	18 419
1982	6 743	1 231	518	8 408	1 024	405	2 389	21 339
1983	6 564	841	577	7 770	1 225	413	1 190	18 715
1984	6 947	432	604	6 340	832	186	1 262	16 943
1985	8 184	336	604	5 729	471	160	1 101	16 925
1986	5 401	398	574	5 618	429	144	962	13 733
1987	4 331	660	534	6 233	355	106	1 168	13 348

* *Natural gas processing plants, transportation, marketing, and oil and gas drilling contractors.*

Source: Energy, Mines and Resources Canada.

Table 9.3. Capital investment by function, 1971-1987

Year	Generation	Transmission	Distribution	Other	Total
			(millions of current dollars)		
1971	915	520	239	73	1 747
1972	1 020	432	229	73	1 754
1973	1 252	366	286	340	2 244
1974	1 805	388	422	138	2 753
1975	2 460	616	547	334	3 957
1976	2 576	794	464	395	4 229
1977	3 085	907	519	373	4 884
1978	3 499	1 290	499	648	5 936
1979	3 892	1 266	570	636	6 364
1980	3 580	1 114	703	712	6 109
1981	4 552	1 387	647	733	7 319
1982	5 026	1 436	937	1 009	8 408
1983	4 882	1 270	766	852	7 770
1984	3 530	1 158	834	818	6 340
1985	2 941	836	1 008	944	5 729
1986	3 214	815	989	600	5 618
1987	2 908	1 258	1 089	978	6 233

Source: Energy, Mines and Resources Canada.

electric utility capital investment by function in 1987. Table 9.3 summarizes capital investment by function for the period 1971-87. Over the past 17 years, the generation component accounted for approximately 59 per cent of total capital investment, while transmission accounted for 18 per cent, distribution 12 per cent, and other investment 9 per cent.

Table 9.4 reports the capital investment of 14 major electric utilities in 1986 and 1987. With the exception of Nova Scotia Power, Ontario Hydro, Alberta Power, TransAlta Utilities and B.C. Hydro, all major utilities increased their capital investment in 1987. Ontario Hydro accounted for about 46 per cent of total utility capital investment in 1987, most of which was related to the ongoing construction of the Darlington nuclear station.

Table 9.4. Capital investment by major electric utility

	1986	1987	Year-over-year change
	(millions of current dollars)		(per cent)
Newfoundland and Labrador Hydro	28	45	7.7
Newfoundland Light & Power	33	40	21.2
Maritime Electric Co. Ltd.	9	12	33.3
Nova Scotia Power	124	117	-6.6
N.B. Power	80	86	7.5
Hydro-Québec	1 537	1 688	9.8
Ontario Hydro	2 641	2 638	-0.1
Manitoba Hydro	223	319	43.0
Saskatchewan Power	187	134	-35.5
Alberta Power	157	133	-15.3
Edmonton Power	129	191	48.1
TransAlta Utilities	231	164	-9.8
B.C. Hydro	148	141	-23.7
Northern Canada Power Commission	14	17	21.4
Canada	5 541	5 725	3.3

Source: Energy, Mines and Resources Canada.

Table 9.5. Major electric utility long-term debt and sources of financing, 1986

	Long-Term Debt	Sources of Long-Term Debt Financing	
	($ millions)	Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 412	39	61
Newfoundland Light & Power	134	93	7
Maritime Electric Co. Ltd.	18	100	0
Nova Scotia Power	1 591	76	24
N.B. Power	2 089	38	62
Hydro-Québec	20 349	41	59
Ontario Hydro	23 494	57	43
Manitoba Hydro	2 652	38	62
Saskatchewan Power	2 162	71	29
Alberta Power	428	100	0
Edmonton Power	623	100	0
TransAlta Utilities	992	94	6
B.C. Hydro	7 472	47	53
Northern Canada Power Commission	96	100	0
Canada	63 512	54	46

Source: Energy, Mines and Resources Canada.

Table 9.6. Comparison of Canadian and U.S. electric utility debt ratios

	1984	1985	1986
		(per cent)	
CANADA			
Publicly owned utilities			
Newfoundland and Labrador Hydro	91	90	88
Nova Scotia Power	94	95	96
N.B. Power	89	88	84
Hydro-Québec	75	76	76
Ontario Hydro	83	84	84
Manitoba Hydro	97	96	96
Winnipeg Hydro	67	68	72
Saskatchewan Power	86	87	87
Edmonton Power	84	80	75
B.C. Hydro	87	86	86
Northern Canada Power Commission	95	96	82
Investor-owned utilities			
Newfoundland Light & Power	46	46	45
Maritime Electric Co. Ltd.	48	43	42
TransAlta Utilities Corporation	42	43	45
Alberta Power	45	43	45
UNITED STATES			
Publicly owned utilities			
Tennessee Valley Authority	84	83	83
Bonneville Power Administration	100	100	100
Power Authority of the State of New York	69	71	72
Investor-owned utilities			
Boston Edison Company	50	51	46
Northeast Utilities	52	53	52
Consolidated Edison Company of New York	34	36	36
Niagara Mohawk Power Corporation	46	46	47
American Electric Power Company	54	53	53
Northern States Power Company	46	46	46
Washington Water Power Company	48	44	48
Pacific Gas and Electric Company	46	48	46

Source: Energy, Mines and Resources Canada.

FINANCING

Electric utilities in Canada normally borrow a portion of their capital requirements from the United States, Western Europe, and Japan. Table 9.5 shows that the outstanding long-term debt of major utilities in Canada was about $64 billion as of December 31, 1986. It is estimated that about $34 billion (54 per cent) was borrowed from domestic markets and $30 billion (46 per cent) from international markets. Of the total $30 billion borrowed internationally, it is estimated that about $26 billion (87 per cent) came from the United States.

Table 9.6 indicates that in 1986 Canadian publicly owned electric utilities had debt ratios ranging from 72 per cent for Winnipeg Hydro to about 96 per cent for Nova Scotia Power and Manitoba Hydro. The debt ratios for investor-owned utilities ranged from 42 per cent to 45 per cent.

High debt ratios, similar to those of Canadian publicly owned utilities, were also common among government-owned utilities in the United States. As Table 9.6 indicates, the Power Authority of the State of New York, the Tennessee Valley Authority, and the Bonneville Power Administration had debt ratios of 72 per cent, 83 per cent, and 100 per cent, respectively. The selected American investor-owned utilities had debt ratios ranging from 36 per cent to 53 per cent, in 1986.

10. Costing and Pricing

ELECTRICITY SUPPLY COSTS

The unit cost of supplying additional electricity increased rapidly during the period 1974-82. However, cost increases have moderated significantly since then. Adjusted for inflation, recent increases in the cost of electricity have been small, and this is expected to be the case for the next several years.

Between 1974 and 1982, there were two key reasons for the rapid increases in the cost of electricity: the high rate of inflation, with an average increase of 10 per cent annually; and the increased cost of fossil fuels, with an average annual increase of 18 per cent. High levels of inflation affect the electric utility industry by increasing the cost of constructing additional facilities and by increasing the cost of borrowed funds.

The average interest rate on new long-term utility debt for the period 1967-87 is shown in Table 10.1. Interest rates started to rise in 1974, which coincided with the first oil crisis, and reached a peak in 1981, after which they dropped substantially. In 1987, interest rates averaged 10.9 per cent, slightly higher than the 10.5 per cent rate registered in 1986.

Table 10.1. Inflation, interest rates, and construction costs, 1967-1987

	Average Interest Rate	Increase in Construction Costs			
		Hydro	Steam	Nuclear	CPI
	(per cent)				
1967	6.7	3.6	1.1	-	3.5
1968	7.8	4.2	2.8	-	4.7
1969	8.6	5.7	6.8	-	4.5
1970	9.3	6.6	7.4	-	3.3
1971	8.5	4.6	6.0	-	2.9
1972	8.4	6.3	6.1	6.9	4.8
1973	8.6	9.2	9.2	9.5	7.6
1974	10.2	18.8	20.5	19.2	10.9
1975	10.7	14.3	13.4	13.1	10.8
1976	10.4	8.9	10.0	9.7	7.5
1977	9.6	5.9	7.9	7.5	8.0
1978	10.0	7.7	8.7	8.0	9.0
1979	10.9	8.7	11.0	12.7	9.2
1980	13.3	10.0	11.6	22.0	10.2
1981	16.3	13.7	11.9	11.4	12.5
1982	15.9	7.2	6.8	5.3	10.8
1983	12.8	4.6	4.1	5.0	5.8
1984	12.5	3.2	2.8	0.1	4.4
1985	11.7	1.7	3.8	4.8	4.0
1986	10.5	4.1	3.5	3.5	4.1
1987	10.9	3.0	2.7	1.9	4.1

Source: Interest rates - McLeod Young Weir Ltd.
Construction costs and CPI - Statistics Canada publications 62-007 and 62-001.

The indices of electric utility construction costs, presented in Table 10.1, show that increases in hydro, steam, and nuclear construction costs between 1969 and 1976 exceeded increases in the CPI. However, since 1977 increases in the CPI have consistently exceeded increases in construction costs, with some minor exceptions for steam in 1979-80 and 1986, and hydro in 1981. The average increase in electric utility construction costs during the period 1967-86 was 7.4 per cent for hydro projects, 7.8 per cent for thermal stations, and 7.8 for nuclear during the period 1971-87, compared to 7.3 per cent for the CPI. In general, electricity construction costs tend to parallel the CPI.

Increases in fossil-fuel costs since 1969 are summarized in Table 10.2. Fuel costs for electricity generation were generally stable until the oil crisis of 1973, when they began to rise. For Canada as a whole, the fuel cost per kW.h of electricity generated from fossil fuels increased more than three times between 1973 and 1986, from 3.1 mills to 10.7 mills. The increase in the cost of fuel from oil generation was much more dramatic, growing from 7.1 mills to 68.02 mills per kW.h during the period 1973-85, an average annual increase of 21 per cent. However, the cost of oil-fired generation declined substantially in 1986, because of the collapse of world oil prices.

The unit cost of fuel generated from coal varies between regions of the country and depends on the type of coal used, its source, and the percentage of total energy supply derived from fossil-fuel plants. The unit fuel cost of electricity generated from western Canadian coal increased from 1.4 mills per kW.h in 1973 to 5.1 mills per kW.h in 1986. In the same period, the cost of coal-fired generation in eastern Canada increased from 4.7 mills to 25.9 mills. Coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Table 10.2. Cost of fuel for electricity generation, 1969-1986

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kW.h)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70

* *Nova Scotia, New Brunswick, and Ontario.*
** *Alberta, Saskatchewan, and Manitoba.*

Source: Calculated from Electric Power Statistics, *Statistics Canada, Catalogue 57-202, various issues.*

The unit fuel cost of electricity generated from natural gas increased substantially between 1973 and 1986, from 3.7 mills per kW.h to 27.1 mills per kW.h, an average increase of about 17 per cent. Over the last 11 years, nuclear-generated electricity has had the lowest unit fuel cost in Canada. In 1986, it cost 4.5 mills per kW.h, compared with 45.2 mills for petroleum, 27.1 mills for natural gas, 25.9 mills for coal burned in eastern Canada, and 5.1 mills for coal used in western Canada. In 1986, all fuel costs for electricity generation were reduced substantially, reflecting the collapse of international oil prices.

PRICING

The average revenue from electricity sales for each province is provided in Table 10.3. Income statements for the major utilities are summarized in Table 10.4. Because electricity rates are regulated to cover costs, the average revenue per unit of electricity began to increase significantly in 1975, with the escalation in the cost of electricity generation. The average annual growth in unit revenue for Canada as a whole was 9.7 per cent during the period 1977-86. The national inflation rate, as measured by the CPI, was 7.8 per cent over the same period. The average revenue from electricity sales for Canada as a whole declined by 2 per cent in 1986, the first decrease since 1966.

Electricity costs differ across the country primarily because of differences in generation mix and the size and geographic distribution of the population being served. Table 10.5 gives monthly electricity costs for selected Canadian cities as of January 1987. Winnipeg had the lowest electricity costs in Canada in all three sectors; Yellowknife had the highest in both the residential and commercial sectors, while Charlottetown had the highest in the industrial sector. Table 10.6 details the average annual rate increases for customers in each province since 1978. In 1987, there were two electric utilities with negative rate changes: Alberta Power and TransAlta.

Figure 10.1 illustrates the movement of the electricity, oil, and natural gas components of the CPI, as well as the CPI itself. It indicates

Table 10.3. Average revenue from electricity sales by province, 1977-1986

	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
	(current cents/kW.h)									
Nfld.	1.7	2.0	2.2	2.3	2.8	3.6	3.7	3.9	4.7	3.9
P.E.I.	5.9	6.4	7.2	8.1	10.0	12.0	12.3	12.8	12.9	11.5
N.S.	3.9	4.4	4.6	4.5	4.9	5.9	6.9	7.5	7.3	6.9
N.B.	2.4	3.2	3.7	4.1	4.8	5.1	5.4	5.5	5.8	5.5
Que.	1.5	1.7	2.0	2.2	2.6	3.1	3.4	3.4	3.5	3.4
Ont.	2.3	2.4	2.6	2.9	3.2	3.6	3.9	4.2	4.5	4.5
Man.	1.9	2.3	2.7	2.8	2.8	2.9	3.1	3.4	3.6	3.6
Sask.	2.4	2.7	2.7	2.9	3.6	4.0	4.2	4.5	4.8	5.0
Alta.	2.7	3.1	3.2	3.4	4.1	4.9	5.2	5.4	5.4	5.4
B.C.	2.1	2.2	2.4	2.6	3.0	3.8	3.8	4.1	4.4	4.2
Yukon	4.1	4.4	4.9	5.3	6.7	8.3	8.3	8.6	9.0	7.8
N.W.T.	6.9	7.7	9.0	10.0	11.5	14.8	17.9	16.7	16.3	15.9
Canada	2.0	2.3	2.5	2.8	3.1	3.7	3.9	4.1	4.3	4.2

Source: Statistics Canada publication 57-202.

Table 10.4. Major electric utilities' statements of income, 1986

	Total Revenue	O&M	Fuel Costs	Power Purchased	Depre-ciation	Taxes	Interest	Exchange Losses	Other Costs	Net Income
	(millions of current dollars)									
Newfoundland and Labrador Hydro	321	53	54	1	23	-	154	-	-	36
Newfoundland Light & Power	245	38	-	140	17	15	16	-	-	19
Maritime Electric Co. Ltd.	54	15	-	22	3	5	4	-	-	5
Nova Scotia Power	484	69	173	12	48	5	147	-	39	(9)
N.B. Power	825	91	131	120	81	-	261	-	112	29
Hydro-Québec	4 734	1 129	-	118	464	272	2 259	189	-	303
Ontario Hydro	4 853	1 014	933	128	705	91	1 585	213	(63)	247
Manitoba Hydro	570	188	-	10	78	38	177	66	-	13
Winnipeg Hydro	84	25	-	36	3	1	7	-	1	11
Saskatchewan Power	847	228	289	-	95	-	245	-	-	(10)
Alberta Power	375	21	128	-	43	73	52	-	-	-
Edmonton Power	271	41	-	93	17	21	14	1	7	77
TransAlta Utilities	916	192	-	13	135	225	148	-	149	54
B.C. Hydro	1 987	278	280	-	233	330	906	-	(65)	25
Northern Canada Power Commission	99	68	-	-	12	-	23	-	3	(1)
Canada	16 665	3 450	1 988	693	1 957	1 076	5 998	469	176	858

Source: Obtained from electric utilities' annual reports, 1986.

that the electricity price component increased more slowly than or equal to the rate of increase of the CPI for the period 1971-76. Since 1977, the electricity price index has been consistently greater than the CPI; however, the increase has been more gradual than for the oil and gas price indices.

'able 10.5. Monthly electricity costs, January 1987 (Dollars)

ector	Residential	Commercial	Industrial
illing Demand (kW)	-	100	1000
'onsumption (kW.h)	1000	25 000	400 000
t. John's	70.01	1 769.98	22 101.29
'harlottetown	87.67	2 593.54	31 469.90
'alifax	72.61	2 261.50	23 365.48
loncton	64.50	2 006.30	20 450.00
lontreal	42.19	1 440.30	16 745.00
'ttawa	48.80	1 272.55	18 102.55
oronto	56.31	1 719.00	20 850.00
/innipeg	39.42	1 042.86	11 834.51
egina	51.00	1 614.24	20 394.24
'algary	51.23	1 469.26	16 963.00
dmonton	51.50	1 563.60	19 980.84
ancouver	53.32	1 332.85	16 071.30
/hitehorse	72.30	2 280.00	-
ellowknife	99.96	2 924.43	-

ource: Statistics Canada publication 57-203.

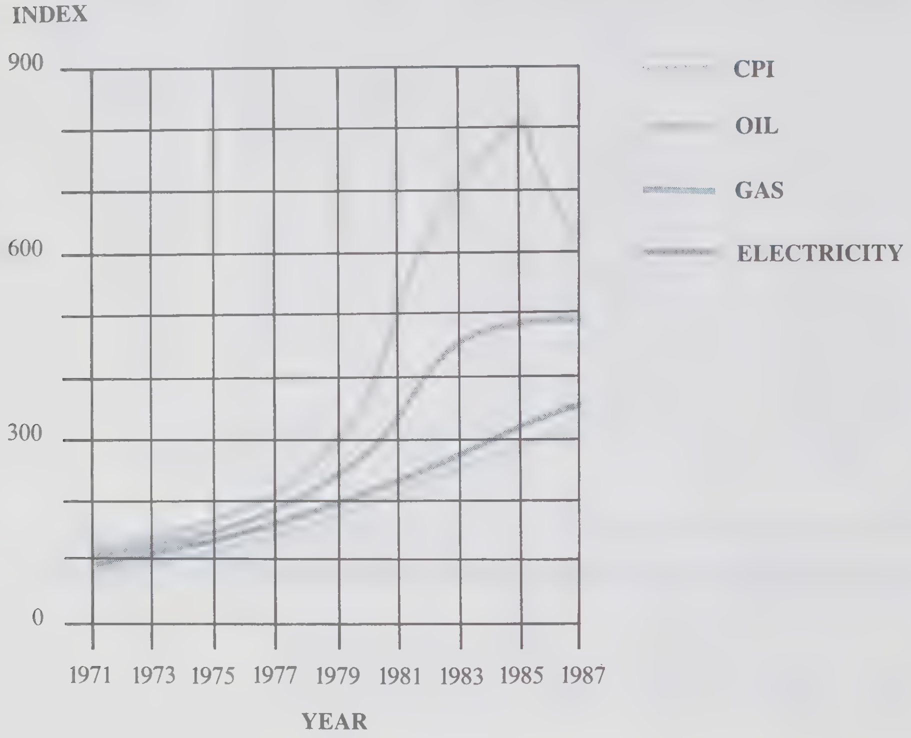
Table 10.6. Average annual rate increases, 1978-1987

			Rate Changes (%): Average of all Customer Classes							
	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
Vewfoundland and Labrador Hydro	25.0	-	19.0	15.8	-	18.2	-	-	-1.7	0
Vewfoundland Light & Power	21.2	12.4	11.8	14.6	-	12.0	-	-	8.66	3.0
Maritime Electric Co. Ltd.	13.0	-	13.1	21.4	-**	-**	-	3.7	-3.75	0
Vova Scotia Power	14.0	12.5	-(b)	36.6	-	-	-	-	-	-
V.B. Power	9.9	7.9	7.8	9.8	-	8.8	6.2	4.6	-	-
Hydro-Québec	18.7	13.7	13.3	10.6	16.3	7.3	4.0	4.0	5.4	4.9
)ntario Hydro	5.7	7.7	7.3	10.0	10.0	8.2	7.5	8.6	4.0	5.0
Manitoba Hydro	14.9	14.4	-(a)	-	-	9.5	7.9	5.0	2.8	9.7
;askatchewan Power	3.3	8.3	7.9	16.1	-	12.6	9.2	-	7.5	7.5
Edmonton Power	8.1	-	26.0	12.0	13.2	8.0	5.0	6.7	0	3.0
TransAlta Utilities	15.6	7.5	-	13.0	4.0	15.0	-	1.7	6.1	-1.8
Alberta Power	-	-	12.3	28.9	-11.6*	2	-	-4.3	-8.6	-5.0
3.C. Hydro	13.4	5.5	7.6	2.6	20.0*	6.0	6.5	3.8	1.84	0

a) The provincial government froze rates from 1979 until 1983.
b) The provincial government froze rates in 1980.
Based on residential category.
** Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.*

;ource: Energy, Mines and Resources Canada.

Figure 10.1. Price indices, 1971-1987



A Newfoundland and Labrador Hydro lineman checks a transmission line in rural Newfoundland. NLH serves 75 000 people in approximately 200 rural communities.

11. Electricity and the Environmental Assessment Process

Most, if not all, electricity generation and transmission projects have some impact on the environment. Fossil-fuel generating stations release chemicals into the atmosphere, and dam and transmission line construction projects have an effect on local plant, animal and aquatic life. Governments, the industry and other groups in society have recognized the need to assess and reduce these impacts. For their part, federal and provincial governments have established processes that are designed to measure and mitigate the environmental consequences of electrical generation and transmission projects.

Despite differences from one jurisdiction to another in the nature of the environment and in the scale and type of project proposed, there are significant similarities in the processes developed by various provincial governments to ensure that the development of electricity generation and transmission projects does the minimum harm possible to the environment.

In most jurisdictions, the developer has initial responsibility for the environmental assessment of activities, and a lead agency (often in the department responsible for the environment) is normally appointed to review this assessment on behalf of the provincial government.

In all jurisdictions, decision-making occurs in discrete steps. Small, routine projects with no substantial or significant impacts are first screened out and allowed to proceed with a minimum loss of time and expense. The screening process is being opened to scrutiny by various means, such as the publication of lists identifying projects and their status.

Projects that may have a major adverse environmental impact are submitted for a more searching (and sometimes more visible and structured) review. Major projects could be subject to public review by an independent board or panel.

The Environmental Impact Statement (EIS) is used in most jurisdictions during the assessment of projects having a potentially major adverse environmental impact. The EIS format is similar in all jurisdictions and involves a project description, an analysis of how the project will impact on the environment, and an identification of proposed mitigating measures. It is normally proposed by the project proponent and is reviewed by the lead and other government agencies or by a public review board or panel.

Most processes involve some form of public review, but the degree of formality varies among jurisdictions from strict adherence to judicial practice to informal community meetings.

The ultimate decision-maker is usually an elected official or officials - a Cabinet minister or the entire Cabinet.

The processes in place in Canadian jurisdictions are outlined below. Some of this material is reviewed in more detail in a report produced under the auspices of the Canadian Council of Resources and Environment Ministers.[1] Since this 1985 report was completed, Manitoba and New Brunswick have introduced major changes and these are reflected in this chapter. Nova Scotia and Prince Edward Island have introduced legislation that will affect their environmental processes, but the proposed changes are not reflected in the notes below because they were not in effect at the time of writing.

FEDERAL PROCESS

The Federal Government's Environmental Assessment Review Process

In December 1973, Cabinet established the federal Environmental Assessment Review Process (EARP) to ensure that the environmental effects of all federal projects are assessed early in the planning process. A federal project is one initiated by a federal agency, or one that involves federal funding or federal property. Federal Crown corporations are not bound by the Cabinet decision, but they are invited to participate in the process.

Under EARP, federal departments are responsible for assessing their own projects. They conduct an initial screening to determine whether a given project will have significant environmental effects. If no such effects are perceived, the project may go ahead with appropriate monitoring by the initiating department.

If significant environmental effects are perceived, a formal review process is undertaken by an Environmental Assessment Panel created by the Minister of the Environment. The Panel is assisted in its work by the Federal Environmental Assessment Review Office. The Panel normally requires that the project sponsor prepare an EIS. If the Minister of the Environment and the initiating minister concur, the scope of the Panel may be extended to include general socioeconomic effects and the need for the project.

Public participation is an integral part of the assessment process. Any person or organization with an interest in the project is provided with an opportunity to appear before the Panel.

[1] William J. Couch, Ph.D. (ed), *Environmental Assessment in Canada: 1985 Summary of Current Practice* (Ottawa, Canadian Council of Resource and Environment Ministers, 1985, catalogue number EM 104-4/1985).

Once a Panel has completed its deliberations and evaluated all information on a project, it prepares a report containing its findings and recommendations. A Panel could recommend that a project not proceed, that it proceed as planned, or that it proceed subject to certain terms and conditions. The recommendations are submitted to the Minister of the Environment and the initiating minister, who must decide to whom the recommendations are directed, to what extent they should be incorporated into terms and conditions governing the project, and in what manner they are to be made public. In the event of a disagreement between the two ministers, the question may be submitted to Cabinet.

In 1987, Environment Canada released a discussion paper, which identified a number of possible changes to the federal government's process identified above.[2] These included a mandatory initial environmental evaluation for certain types of proposals and possible publishing of the results. At the time of writing this chapter, many of the concepts contained in the discussion paper were being reviewed by federal departments and agencies.

PROVINCIAL PROCESSES

British Columbia

The principal legal basis for British Columbia's energy project review process is the Utilities Commission Act, 1980. Major energy projects cannot proceed until the proponent has received either an Energy Project Certificate or a Certificate of Public Convenience and Necessity, both of which specify the terms and conditions under which the facility may be constructed and operated.

In order to obtain a Certificate, a proponent (other than a public utility) must first provide a prospectus, then an application, to an Energy Project Coordinating Committee (EPCC). This steering group is chaired by the Ministry of Energy, Mines and Petroleum Resources and includes representatives from the Ministry of Environment and Parks and a member of the British Columbia Utilities Commission (BCUC). In the application, the proponent must address environmental impacts, impact management strategies, benefit and costs, and proposals for compensation, mitigation and monitoring. The EPCC, through several inter-ministry working groups, reviews the material and formally submits it to the ministers of Environment and Parks and of Energy, Mines and Petroleum Resources, together with recommendations. Generally, the recommendations are either for a public hearing by the BCUC or exemption from provisions of the Utilities Commission Act.

If an application is referred to the BCUC, a report is sent to the two ministers once the public hearing is completed. The Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment and Parks, then announces the Cabinet decision.

If a public utility applies for an Energy Project Certificate, the ministers may refer the application to the BCUC for review and decision. This may include holding a public hearing and may result in the issuance, directly by the Commission, of a Certificate of Public Convenience and Necessity.

Alberta

Alberta's Environmental Impact Assessment (EIA) process was established by the Land Surface Conservation and Reclamation Act of 1973. Pursuant to Section 8 of the Act, the Minister of the Environment may require a proponent of a proposed development to prepare an EIA report if he or she believes it is in the public interest to do so. The purpose of an EIA is to provide information to the public and the government to enable early identification and resolution of significant adverse effects on the environment.

The Alberta EIA process is implemented in accordance with the Alberta EIA Guidelines and administered by the Alberta Department of Environment. Most major resource developments proposed in Alberta are subject to this requirement. Major thermal and hydro generation undertakings require an EIA, and smaller projects must submit the environmental information necessary for the required approvals. In preparing an EIA, the proponent (a person, company, provincial agency or Crown corporation) must consult with the public and provide opportunities for the public to participate in the preparation and review of the EIA.

Energy projects require the approval of the Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment. Consequently, Alberta Environment and the ERCB coordinate their respective information requirements and reviews of energy projects. EIAs on energy projects are filed with Alberta Environment and the ERCB as part of the application to the ERCB. The ERCB may require a public hearing to be held for a project. After the ERCB makes its decision, Alberta Environment issues detailed environmental permits and licences.

[2] Environment Canada, *Reforming Federal Environmental Assessment: A Discussion Paper* (Ottawa, Minister of Supply and Services, Canada, 1987, catalogue number EN 106-5/1987).

Saskatchewan

The Environment Assessment Act of 1980 provides for environmental impact assessments of major development projects, and exemptions may be granted by Cabinet only in cases of emergency.

The province's environmental impact assessment and review process is administered by the Saskatchewan Department of Environment and Public Safety, and projects may proceed only with the approval of the Minister of Environment and Public Safety. Proposals are screened by the department to determine whether an EIA is required and, if so, its nature and scope. If it is determined that an EIA is not required, the project may proceed subject to all other statutory requirements.

Where an EIA is required, proponents are encouraged to undertake a public participation program as early as possible so that public comments and recommendations may be considered during the preparation of the Environmental Impact Statement (EIS). Further safeguards are built into the process, such as a minimum 30-day public review of the EIS and the power given to the minister to establish a Board of Inquiry, which may hold public hearings. The final decision to approve (with or without conditions) or to refuse the proposed development rests with the minister.

Manitoba

The Manitoba Environment Act of 1988 replaces the former Clean Environment Act of 1968 and the Environmental Assessment and Review Process, adopted as provincial Cabinet policy in 1975.

The new Act requires that the planning of prospective developments, both public and private, take into consideration the interests of all affected parties. It also requires anyone planning a project that could affect the environment to register it with the Department of Environment and Workplace Safety and Health, and conduct an environmental assessment. Major projects require ministerial approval before proceeding.

Activities that would be affected by the Environment Act are described as "developments." A development can take one of three forms, which accordingly have been separated into three separate classes. Class 1 developments are essentially pollution-related. Class 2 developments are activities with significant environmental impact caused by factors other than pollution or by factors in addition to pollution. Class 3 developments are relatively few in number and involve large-scale projects such as major hydro developments, water diversions, and industrial developments.

Under the provisions of the Act, any person or organization undertaking a development proposal is required to register the development with the Department of Environment and Workplace Safety and Health at an early stage in the planning schedule. Representatives from government departments with an interest in the development prepare appropriate study guidelines for the proponent to apply in preparing an assessment. The type of assessment developed focuses on the main issues associated with the project, while keeping the review process as expeditious as possible. The public is provided with an opportunity for input at selected points of the review process, depending on the type of assessment undertaken. The final product of the process is an environmental licence with terms and conditions specific to the proposal. Alternatively, a licence to proceed could be refused on the grounds of unacceptable environmental damage.

Ontario

The Minister of the Environment is responsible for the administration of the Environmental Assessment Act, which promotes improved planning by providing for the involvement of the public and government ministries and agencies in the environmental assessment, planning and approvals process. (The environmental process in Ontario is also subject to the terms of the Consolidated Hearings Act, 1981. This summary, however, deals only with the Environmental Assessment Act, which is one of two major pieces of provincial legislation affecting the environment. Further details of the Consolidated Hearings Act may be obtained from *Environmental Assessment in Canada*[3] or from the October 1987 issue of *Canadian Environmental Law Reports*.[4])

The environment minister may, with the approval of Cabinet, exempt proponents from the application of the Environmental Assessment Act, which currently applies to the activities of provincial ministries, municipalities and conservation authorities. Only those undertakings of the private sector specifically or generically designated by regulation are subject to the Act. Proponents planning an undertaking must determine if the Act applies, and where it does not apply or where an exemption has been granted, the activity may proceed. If the Act applies, the proponent must prepare an Environmental Assessment (EA), which is reviewed by the Ministry of Environment and other

[3] William J. Couch, Ph.D., *op. cit.*

[4] *Canadian Environmental Law Reports*, New Series, Vol. 1, Part 6, October 1987.

interested provincial and federal government organizations.

The Ministry subsequently prepares its comments which, together with the EA, are released for a minimum 30-day public review. A hearing of the Environmental Assessment Board may then be requested by the reviewers, the public or the proponent. Should the minister decide that a Board hearing is not required, the minister — with the concurrence of Cabinet — will make a decision to approve, with or without conditions, or refuse the undertaking. When the minister decides to refer the matter to a Board hearing, the Board must give reasonable notice of the hearing, which is open to the public. The minister or Cabinet has 28 days to make any amendments to the Board's decision; if no amendments are made within this period, the Board's decision becomes binding.

Quebec

In Quebec, the process of environmental assessment varies depending on whether a project is in the south of the province or in a territory that is the subject of agreements with native people.

The 1972 Environment Quality Act was amended significantly in 1978 to implement an environmental impact assessment and review procedure. By regulation, this procedure applies essentially to projects in the south of the province. When a project is subject to the procedure, the proponent must submit an EIA to the Department of the Environment for an admissibility analysis and an evaluation of the environmental acceptability of the project. All projects are subject to a public consultation period, during which any citizen may ask the Minister of the Environment to hold a public hearing. Citizens can thus voice their views before the project is referred to Cabinet for acceptance or refusal.

In the northern Quebec territories, the provincial government has implemented a particular procedure to assess and review the environmental and social impacts of a given project. A distinctive feature of this procedure is the use of bipartite or tripartite committees on which native people are always represented. These committees advise the Deputy Minister of the Environment throughout the various stages of the authorization process. This procedure, which was incorporated into the Environment Quality Act, stemmed from the James Bay and Northern Quebec Agreement (1975) and the North-eastern Quebec Agreement (1978).

New Brunswick

New Brunswick's Regulation on Environmental Impact Assessment was promulgated in July 1987, to provide a legislative framework for environmental planning, including opportunities for public involvement. The Regulation, which replaced the province's 1975 Policy on Environmental Assessment, is designed to identify the environmental impacts associated with development proposals, in advance of their implementation.

Under the Regulation, individuals, companies or public agencies proposing certain types of projects are required to register information about the project with the Minister of Municipal Affairs and Environment at an early stage in the planning cycle. The minister then screens the proposal to determine whether it is likely to have significant environmental impacts, including both socio-economic and biophysical effects.

If it appears that the project's impacts are likely to be significant, the minister will inform the proponent that an EIA is required, and staff from the Department of Municipal Affairs and Environment will work with the proponent in preparing initial draft guidelines for the EIA Study. A Review Committee, consisting of technical specialists from government agencies potentially affected by the proposal, is appointed by the minister to formulate draft guidelines for the Study. These draft guidelines, which identify the important environmental issues to be addressed, may then be issued by the minister for public comment, and any interested party may provide written comments to the minister.

The principal objective of the EIA Study is to predict the project's impacts, should it proceed. Information gathered during the study is compiled in a draft Environmental Impact Assessment Report, which is then carefully examined by the Review Committee. If, on the advice of the Committee, the minister is satisfied that the report adequately addresses all aspects of the guidelines, a second and more comprehensive opportunity for public involvement begins. A summary of the report, comments of the Review Committee, and full copies of the final report are released for public review and comment.

A public meeting to discuss the EIA takes place. Thereafter, the minister reviews the study and public comments, and then recommends to the Lieutenant-Governor in Council whether or not the project should proceed.

Nova Scotia

The legal bases for environmental impact assessment in Nova Scotia are the Environmental Protection Act and the Water Act.

The Nova Scotia Department of the Environment (NSDOE) is responsible for screening all projects submitted and advising the minister on those that may have a significant and adverse

environmental impact. After reviewing NSDOE's advice, as well as any public concern expressed, the minister decides whether a project requires an EIA. Where it is decided one is required, the proponent prepares a draft EIA and submits it to NSDOE. The department and other interested provincial and federal agencies review the EIA, and the NSDOE then recommends to the minister whether the project should be approved, with or without conditions, or refused.

The public may participate in the process through a number of mechanisms. The minister, based on NSDOE recommendations and the views of the public, decides whether the project should proceed and, if so, under what conditions.

Prince Edward Island

In 1973, P.E.I.'s Executive Council directed provincial departments and agencies to screen all energy developments for potentially significant adverse environmental impacts.

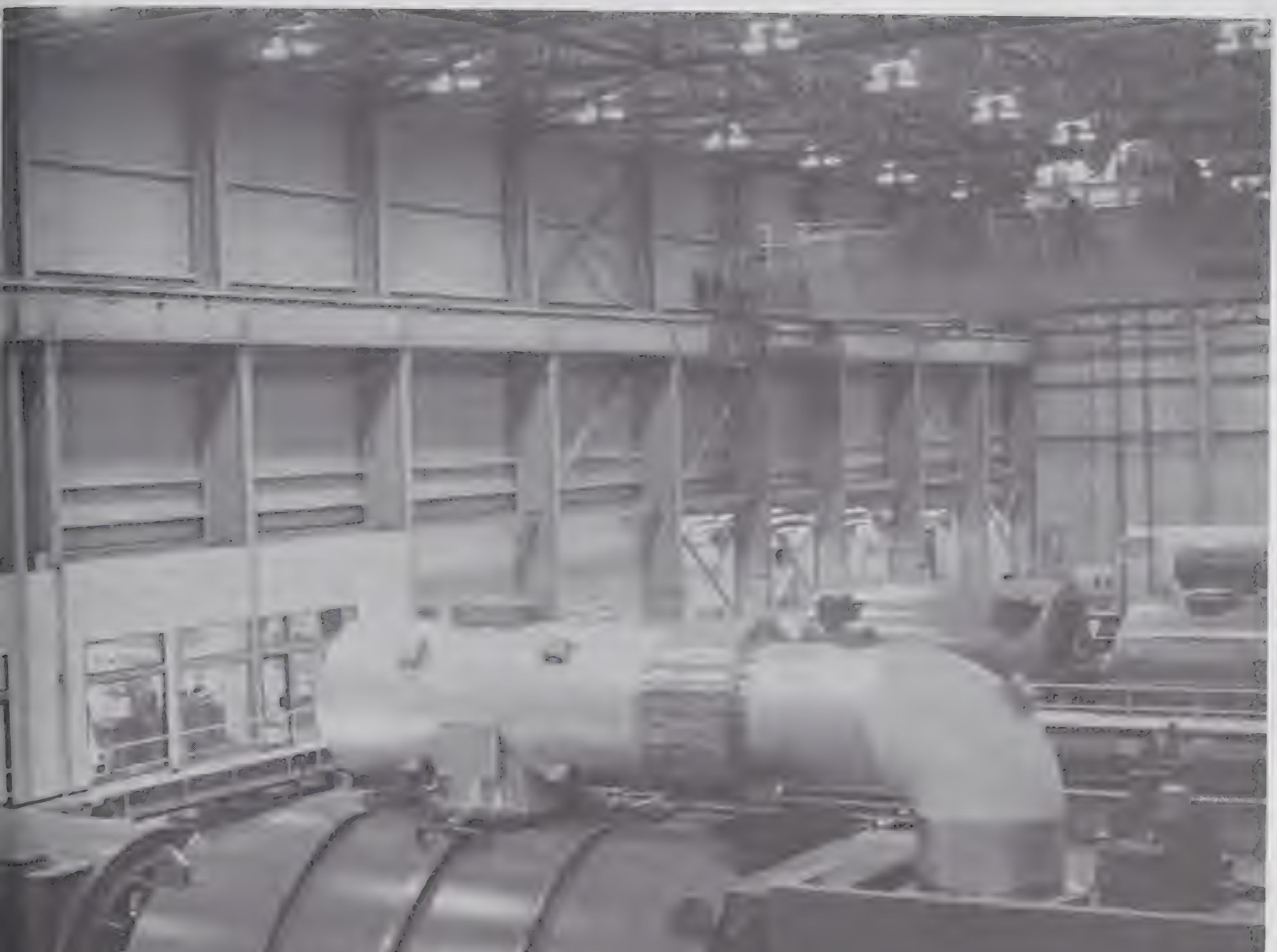
With respect to utilities, the Public Utilities Commission may issue project-specific guidelines to the proponent for the preparation of an EIS, if it believes that the project may adversely affect the environment. A copy of the EIS is then sent by the Commission to the Executive Council for its consideration. The Council may make a decision on the evidence available or it may determine that the public interest requires public hearings to be held in the locality affected by the project. After the public hearings, the Commission examines the evidence and issues its findings to the Executive Council.

Newfoundland

The province's environmental assessment process operates under the authority of the Environmental Assessment Act of 1980, which is administered by the Department of Environment.

The preliminary design of any undertaking that may have a significant adverse environmental impact must be registered with the Minister of Environment. The minister, on the advice of the department, decides whether or not an EIS is required. If an EIS is not required, the undertaking may proceed subject to other relevant acts or regulations.

Where an EIS is required, it is prepared by the proponent; the minister then makes it available for public review and comment. Should strong public interest be expressed, the minister may recommend to Cabinet that an Environmental Assessment Board be appointed to conduct public hearings. The minister makes the Board's report public, delivers copies to Cabinet, and subsequently recommends to Cabinet whether the undertaking should be permitted to proceed, with or without conditions, or whether permission should be refused.



An interior view of Newfoundland and Labrador Hydro's Holyrood thermal generating station, showing the three generating units. Work is now underway to uprate two of the units from 150 MW to 175 MW each.

12. Electricity Outlook

Forecasting electricity demand has become a difficult task in recent years. This is largely a result of the economic dislocation caused by rapidly rising energy prices, particularly between 1975-77 and 1980-82. The effects of higher energy prices have been felt globally, and adjustments have been made worldwide in the amount, types, and uses of energy. The collapse of world oil prices in 1986 has added to the uncertainty. Adjustments in energy-use patterns continue to make economic forecasting difficult, and this economic uncertainty, in turn, leads to uncertainty about future electricity demand.

Despite this uncertainty, forecasts of electricity demand are essential to ensure that sufficient generating capacity is available when it is needed. The long lead time in the construction of new generating facilities makes it necessary for utilities to calculate future demand many years in advance. This chapter presents projections of electrical energy demand, peak demand, generating capacity, electricity generation, and fuel requirements for the period 1987-2005. Capital expenditures for the period 1987-97 are also summarized.

FORECASTS OF ENERGY DEMAND

Because economic growth and population growth over the next 18 years are expected to be significantly lower than the previous 27-year period, electricity growth is also expected to be lower. Table 12.1 summarizes electricity demand forecasts for the ten provinces and two territories during the period 1987-2005. The projections of electrical energy demand within the service areas of the major utilities were prepared by the utilities and provided to Energy, Mines and Resources Canada (EMR) in February 1988. Electricity demand for smaller utilities and industrial establishments was projected by the National Energy Board. The Electrical Energy Branch of EMR combined these two sources of forecasts and produced an overall electricity demand forecast for the provinces and territories. Table 12.1 indicates that Alberta is expected to have the highest electricity demand growth, with an average growth rate of 3.4 per cent during the period 1987-2005, followed by Nova Scotia at 3.0 per cent. Ontario's demand is expected to be 2.1 per cent, which is the national average, and Quebec's is expected to grow at a rate of only 1.7 per cent annually.

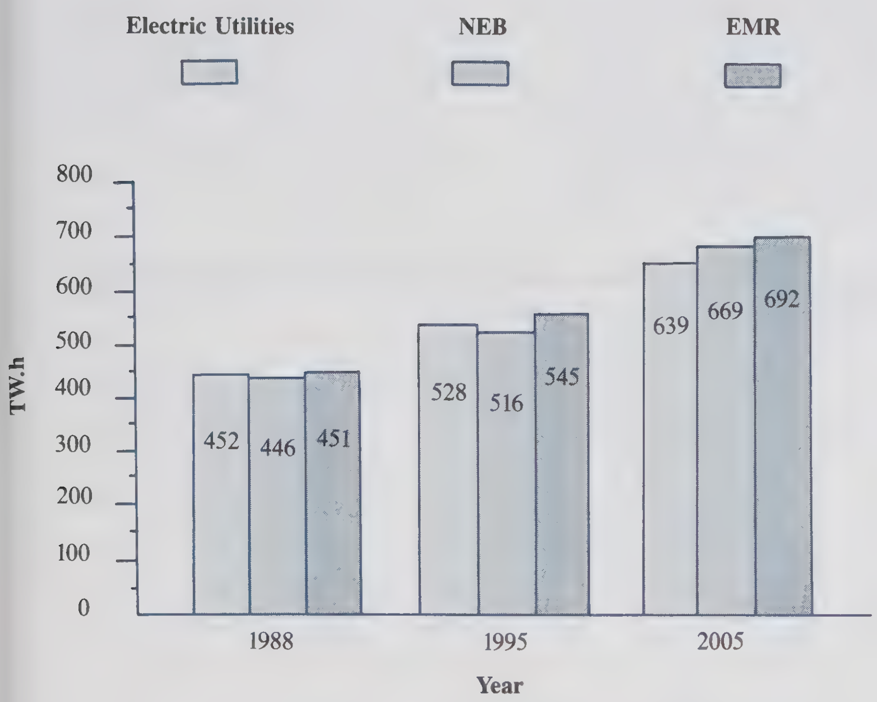
Figure 12.1 illustrates various forecasts for overall electricity demand in Canada. Included for comparison are the latest forecasts derived from EMR's Interfuel Substitution Demand Model, the National Energy Board Model, and forecasts provided mainly by the major electric utilities. The utilities' projection of electricity demand for the next 18 years appears to be on the low side at 2.1 per cent per year, compared with the NEB's 2.4 per cent, and EMR's 2.6 per cent. All three forecasts, however, are substantially lower than the 5.2 per cent achieved during the period 1960-1987.

Table 12.1. Forecasts of domestic energy demand

	1987	1990	1995	2000	2005	Average Annual Growth Rate 1987-2005
			(GW.h)			(%)
Nfld.	9 697	10 647	11 485	12 359	13 243	1.8
P.E.I.	647	709	771	828	889	1.8
N.S.	8 326	9 798	11 226	12 636	14 127	3.0
N.B.	12 376	13 832	16 003	17 835	19 531	2.6
Quebec	158 196	161 099	183 350	200 350	214 748	1.7
Ontario	132 174	142 074	159 927	175 290	191 160	2.1
Man.	15 862	17 792	19 939	21 748	23 814	2.3
Sask.	12 451	13 553	15 528	17 311	19 190	2.4
Alta.	36 588	39 873	48 698	59 928	67 190	3.4
B.C.	50 934	55 506	60 508	66 455	73 944	2.1
Yukon	432	474	523	577	638	2.2
N.W.T.	467	526	529	552	570	1.1
Canada	438 150	465 883	528 487	585 869	639 044	2.1

Source: Canadian electric utilities, and National Energy Board.

Figure 12.1. Comparison of electricity demand forecasts



FORECASTS OF PEAK DEMAND

Table 12.2 reports forecast peak demand growth for the provinces and territories, as projected by the major electric utilities for the period 1987-2005. With the exception of Ontario, Manitoba, and the Yukon, all other provinces and the Northwest Territories appear to have a larger growth rate in peak demand than in energy demand. This suggests that the load factor for Ontario, Manitoba, and the Yukon will improve during this period, while the load factor for the remaining provinces and territory will decrease. The load factor for Canada as a whole is expected to decrease, from 67 per cent in 1987 to about 65 per cent by the year 2005.

FORECASTS OF GENERATING CAPACITY

To meet the forecast growth in electricity demand shown in Tables 12.1 and 12.2, total installed generating capacity in Canada is expected to increase at an average

Table 12.2. Forecasts of domestic peak demand

	1987	1990	1995	2000	2005	Average Annual Growth Rate 1987-2005
			(MW)			(%)
Nfld.	1 758	1 858	2 067	2 283	2 484	1.9
P.E.I.	105	116	126	135	159	2.3
N.S.	1 484	1 818	2 097	2 406	2 734	3.5
N.B.	2 178	2 619	3 048	3 413	3 713	3.0
Quebec	26 717	28 749	32 893	36 263	39 143	2.1
Ontario	22 418	24 397	26 641	28 954	31 376	1.9
Man.	3 247	3 498	3 927	4 285	4 709	2.1
Sask.	2 252	2 509	2 874	3 179	3 519	2.5
Alta.	5 525	6 242	7 478	9 104	10 154	3.5
B.C.	8 514	9 546	10 556	11 726	13 176	2.5
Yukon	69	72	79	88	97	1.9
N.W.T.	89	113	117	122	126	2.0
Canada	74 356	81 537	91 903	101 958	111 390	2.3

Source: Canadian electric utilities, and National Energy Board.

annual rate of 1.4 per cent, from almost 101 000 MW at the end of 1987 to about 129 000 MW by the end of 2005. This level of growth is significantly lower than energy and peak demand growth, reflecting the current excess capacity situation in most of the provinces. Forecasts of installed capacity by province are summarized in Table 12.3, and forecasts of installed capacity by fuel type for Canada as a whole are displayed in Table 12.4.

The largest share of total Canadian capacity over the next 18 years will continue to be hydro, increasing slightly from 57 per cent of total capacity in 1987, to 59 per cent by the year 2005. Nuclear generating capacity, as a share of total capacity, will remain relatively stable at 12 per cent through the period, while coal-fired capacity is expected to increase moderately, from 17 per cent in 1987 to about 19 per cent in 2005. The capacity share of natural gas is expected to decrease slightly, from 5 per cent to 4 per cent for the period 1987-2005. The share of oil-fired capacity is also expected to decline, from 8 per cent in 1987 to 6 per cent by 2005. Thus coal, nuclear, and hydro will continue to account for most of the electricity generated in Canada. In 1987, these three sources accounted for 87 per cent of total capacity, and this percentage is expected to

Table 12.3. Forecasts of installed generating capacity by province

	1987	1990	1995	2000	2005	Average Annual Growth Rate 1987-2005
			(MW)			(%)
Nfld.	7 402	7 482	8 297	8 306	8 419	0.7
P.E.I.	122	124	124	124	124	0.1
N.S.	2 346	2 055	2 777	3 105	3 565	2.4
N.B.	3 490	3 430	3 762	4 397	4 797	1.8
Quebec	27 644	28 814	30 905	36 087	39 604	2.0
Ontario	32 123	31 927	34 405	34 984	35 127	0.5
Man.	4 137	4 347	5 321	5 707	6 357	2.4
Sask.	2 948	2 826	3 311	3 673	4 103	1.9
Alta.	7 605	7 622	8 618	10 281	11 915	2.5
B.C.	12 508	12 560	12 555	12 855	14 570	0.9
Yukon	123	123	126	128	132	0.4
N.W.T.	190	189	190	193	194	0.1
Canada	100 638	101 599	110 511	119 930	128 907	1.4

Source: Canadian electric utilities, and National Energy Board.

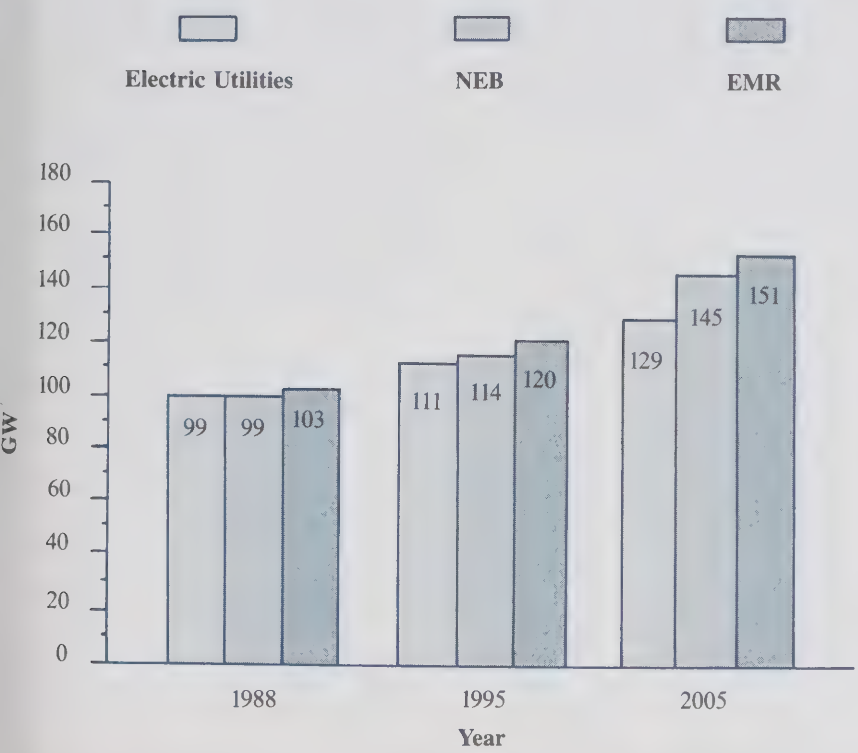
Table 12.4. Forecasts of installed generating capacity by fuel type in Canada

	1987	1990	1995	2000	2005
			(MW)		
Coal	17 420	17 773	20 070	22 030	24 632
Oil	7 860	7 286	7 322	7 543	7 649
Natural gas	5 157	3 459	3 829	4 520	4 962
Nuclear	11 928	13 857	15 619	15 597	15 597
Hydro	57 731*	58 736	63 113	69 632	75 444
Other	542	488	558	608	623
Total	100 638	101 599	110 511	119 930	128 907

* *Includes tidal power.*

Source: Canadian electric utilities, and National Energy Board.

Figure 12.2. Comparison of generating capacity forecasts



increase slightly to 90 per cent by the year 2005.

Figure 12.2 compares various forecasts of total generating capacity in Canada for the period 1988-2005. Again, the electric utilities' forecasts are on the low side. Both EMR and the NEB have projected larger generation requirements. Between 1987 and 2005, the electric utilities have projected new capacity additions of about 28 GW, or about 1650 MW per year. The NEB projects capacity additions of 44 GW, or about 2590 MW per year; EMR projects new additions of 50 GW, or about 2940 MW per year. EMR's projections are significantly higher than the electric utilities' own projections.

FORECASTS OF ELECTRICITY GENERATION

Utility forecasts of electricity generation by province for the period 1987-2005 are presented in Table 12.5. As the data indicate, Quebec is expected to remain the largest electricity producer in

Table 12.5. Utility forecasts of electricity generation by province

	1987	1990	1995	2000	2005	Average Annual Growth Rate 1987-2005
			(GW.h)			(%)
Nfld.	40 090	39 943	39 932	40 549	41 558	0.2
P.E.I.	164	225	225	225	225	1.8
N.S.	7 749	9 619	11 053	12 463	13 954	3.3
N.B.	12 493	14 074	20 265	23 986	26 236	4.2
Quebec	156 952	154 843	174 714	191 458	206 054	1.5
Ontario	131 582	145 770	166 517	179 450	194 340	2.2
Man.	19 902	20 030	23 399	26 610	25 069	1.3
Sask.	12 440	13 234	14 982	16 889	18 733	2.3
Alta.	36 770	39 873	48 663	59 928	67 190	3.4
B.C.	63 067	54 145	56 790	57 741	66 471	0.3
Yukon	432	474	523	577	638	2.2
N.W.T.	467	573	576	602	622	1.6
Canada	482 108	493 723	557 439	610 478	660 880	1.8

Source: Canadian electric utilities, and National Energy Board.

Canada, followed by Ontario. Alberta is expected to overtake British Columbia as the third largest electricity-producing province by the year 2000.

Utility forecasts of electricity generation by principal fuel type for Canada are summarized in Table 12.6. The data suggest that hydro-based generation will continue to be the most important source of electric energy in Canada, although its share of total electricity production will decline from 65 per cent in 1987 to about 58 per cent in 2005. Coal-fired production is expected to decrease, in both quantity and market share, between 1987 and 1990, and then steadily increase to about 22 per cent of total electricity generation by the year 2005. The 1987-90 decrease is due mainly to Ontario Hydro's plan to reduce its coal-fired generation from 32 TW.h in 1987 to only 14 TW.h by 1990. This substantial reduction will be offset by increasing nuclear production from the Darlington nuclear station.

Even though falling world oil prices in recent years have provided electric utilities with an economic incentive to utilize their existing oil-fired stations in the short term, oil prices are not expected to remain low for a long period of time. In the long term, oil-fired stations will continue to be used mainly as peaking capacity and to serve energy demand in remote locations. Beyond 1990, the use of oil in electricity generation is expected to decrease with the overall increase in demand. By the year 2005, the share of electricity generated from oil is expected to be 1.4 per cent of total electricity generation, compared with 1.8 per cent in 1987. It is expected that natural gas will slightly increase its share in electricity generation, from about 1.5 per cent in 1987 to about 2.2 per cent by 2005. The increased use of natural gas for electricity generation will come mainly from industrial establishments in Ontario and major utilities in Alberta. Nuclear generation is expected to reach a peak in both quantity and market share by the year 1995. The nuclear share of electricity generation is expected to increase from 15 per cent in 1987 to a peak of about 21 per cent in 1995, and then decline to about 17 per cent by the year 2005. A comparison of various electricity generation forecasts is shown in Figure 12.3.

FORECASTS OF FUEL REQUIREMENTS

Forecast fuel requirements are reported in Table 12.7. They are based on the forecasts of energy generation given in Table 12.6.

Coal consumption for electricity generation is expected to decrease significantly from about 43 million tonnes in 1987 to 37 million tonnes in 1990, because of the substantial reduction in electricity generation from coal-fired stations in Ontario. Nevertheless, the use of coal will increase to about 45 million tonnes in 1995 and will reach 69 million tonnes by the year 2005. The major increase in coal use will be in Alberta, New Brunswick, and Nova Scotia. Ontario is expected to increase its use of coal from 5.1 million tonnes in 1995 to about 16 million tonnes by the year 2005.

Oil consumption is expected to increase moderately from 2.1 to 2.3 million cubic metres (or 14 million barrels) between 1987 and 1990, and then to decline gradually to about 1.9 million cubic metres (or 12 million barrels) by the year 2005. Oil will be used primarily for peaking purposes and in remote locations.

Over the forecast period, 1987 to 2005, the use of natural gas for electricity generation is projected to increase from 2979 million cubic metres to 6051 million cubic metres. This increase is larger than those forecast for coal, oil, and uranium. Major industrial establishments, mainly in Alberta and Ontario, are the largest users of

Table 12.6. Forecasts of electricity generation by fuel type in Canada

	1987	1990	1995	2000	2005
			(GW.h)		
Coal	78 280	63 493	80 318	115 222	143 061
Oil	8 666	10 887	9 586	9 486	9 053
Natural gas	7 095	8 104	10 429	12 327	14 512
Nuclear	72 888	98 859	116 297	109 030	109 030
Hydro	313 189	301 024	337 983	360 703	381 464
Other	1 990	2 356	2 826	3 710	3 760
Total	482 108	493 723	557 439	610 478	660 880

Source: Canadian electric utilities, and National Energy Board.

Figure 12.3. Comparison of electricity generation forecasts

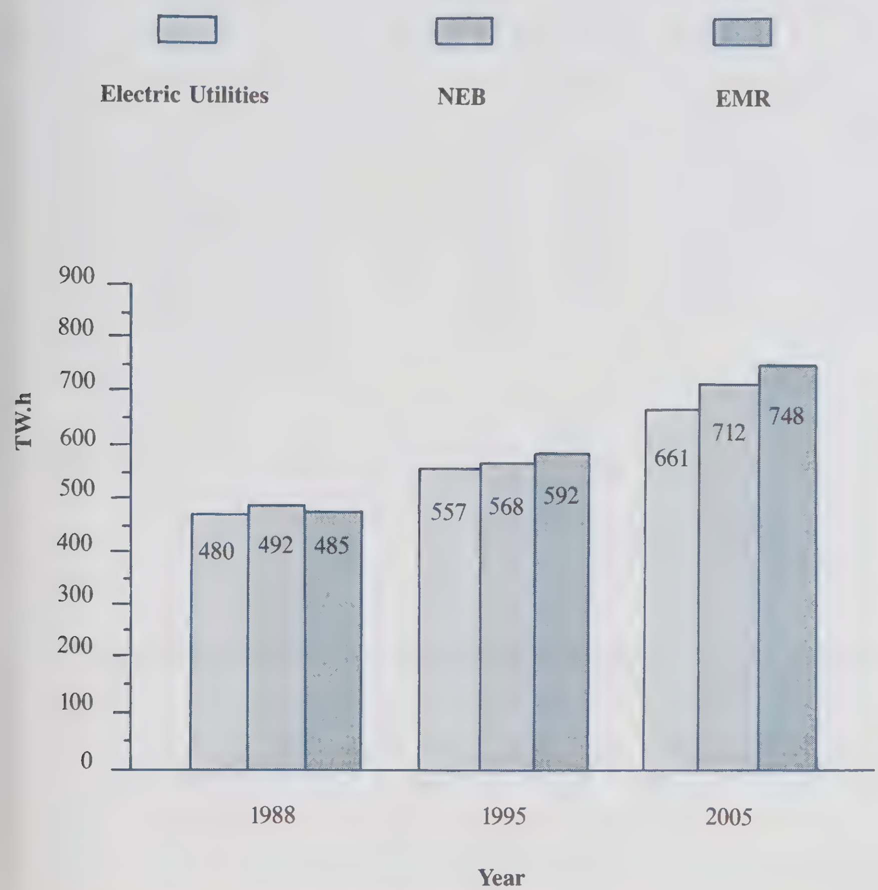


Table 12.7. Fuels required for electricity generation

	Coal (10^3 tonnes)	Oil (m^3)	Natural Gas (10^6m^3)	Uranium (tonnes)
1987	42 500	2 053 387	2 979	1 306
1990	36 688	2 336 912	3 325	1 846
1995	44 672	2 055 659	4 362	2 068
2000	59 223	2 020 335	5 917	1 933
2005	68 603	1 902 529	6 051	1 933

Note: 1 m^3 oil = 6.3 bbls
1 m^3 gas = 35.5 ft^3
1 tonne = 1000 kg

Source: Canadian electric utilities, and National Energy Board.

natural gas for electricity generation; their share accounted for about 84 per cent in 1987, and is expected to be 63 per cent by the year 2005. The major electric utilities in Alberta also use a substantial amount of natural gas for electricity generation; their share is expected to increase from 16 per cent to 37 per cent over the period 1987-2005.

With nuclear energy becoming an increasingly important component of the Canadian electricity supply, the use of uranium for electricity generation is expected to increase substantially from 1306 tonnes in 1987 to 2068 tonnes in 1995; it will then stabilize at 1933 tonnes through to the year 2005.

FORECASTS OF CAPITAL EXPENDITURES

Table 12.8 summarizes capital expenditures for major utilities in each of the provinces and territories for the period 1988-97. Over the next ten years, major utilities in Canada are expected to invest about $95 billion in facilities. Quebec will be the largest investor with $39 billion, accounting for about 41 per cent of the total. Ontario is expected to invest about $29 billion in electrical energy, or about 30 per cent of Canada's total. Most of this expenditure will be for the Darlington nuclear station.

Alberta ranks third in projected capital investment, with $7 billion or 7 per cent of the total. This investment will mainly be in coal-fired stations. Manitoba is expected to spend more than $5 billion in capital investment, accounting for about 6 per cent of Canada's total.

The electric utilities' capital investments by function are presented in Table 12.9. It is expected that generating facilities will account for 49 per cent of the total for the period 1988-1997, transmission 25 per cent, distribution 14 per

Table 12.8. Capital expenditures for major electric utilities, 1987-1997

	1987*	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
	(millions of current dollars)										
Newfoundland	86	172	164	204	168	137	142	222	348	524	644
Prince Edward Island	11	11	22	12	11	15	12	10	11	15	16
Nova Scotia	117	133	221	270	235	296	312	322	206	208	274
New Brunswick	86	131	175	312	484	316	376	419	431	570	400
Quebec	1 688	2 240	2 460	2 850	3 308	3 635	3 590	4 782	5 596	4 884	5 548
Ontario	2 638	2 900	2 700	2 500	2 300	2 200	2 500	2 900	3 700	3 600	3 200
Manitoba	319	459	453	439	405	282	290	394	523	881	1 105
Saskatchewan	134	210	341	327	348	220	248	352	410	334	350
Alberta	488	736	683	573	618	493	579	717	631	754	813
British Columbia	142	238	193	175	154	186	258	270	358	469	611
Yukon	3	2	2	2	2	2	2	2	2	2	2
Northwest Territories	14	27	31	12	10	6	85	9	9	9	9
Canada	5 726	7 259	7 445	7 676	8 043	7 788	8 394	10 399	12 225	12 250	12 972

* *Actual data*

Source: Canadian electric utilities.

Table 12.9. Capital expenditures by function, 1987-1997

	1987*	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
	(millions of current dollars)										
Generation	2 644	3 270	3 252	3 515	3 665	3 673	4 031	5 227	6 358	6 723	6 715
Transmission	1 140	1 876	2 116	1 985	2 048	1 841	1 882	2 602	3 179	2 622	3 186
Distribution	1 063	1 188	1 154	1 170	1 202	1 320	1 335	1 382	1 467	1 551	1 591
Other	879	925	923	1 006	1 128	954	1 146	1 178	1 221	1 354	1 480
Total	5 726	7 259	7 445	7 676	8 043	7 788	8 394	10 399	12 225	12 250	12 972

* *Actual data*

Source: Canadian electric utilities.

cent, and other facilities 12 per cent.

FORECASTS OF ELECTRICITY EXPORTS TO THE UNITED STATES

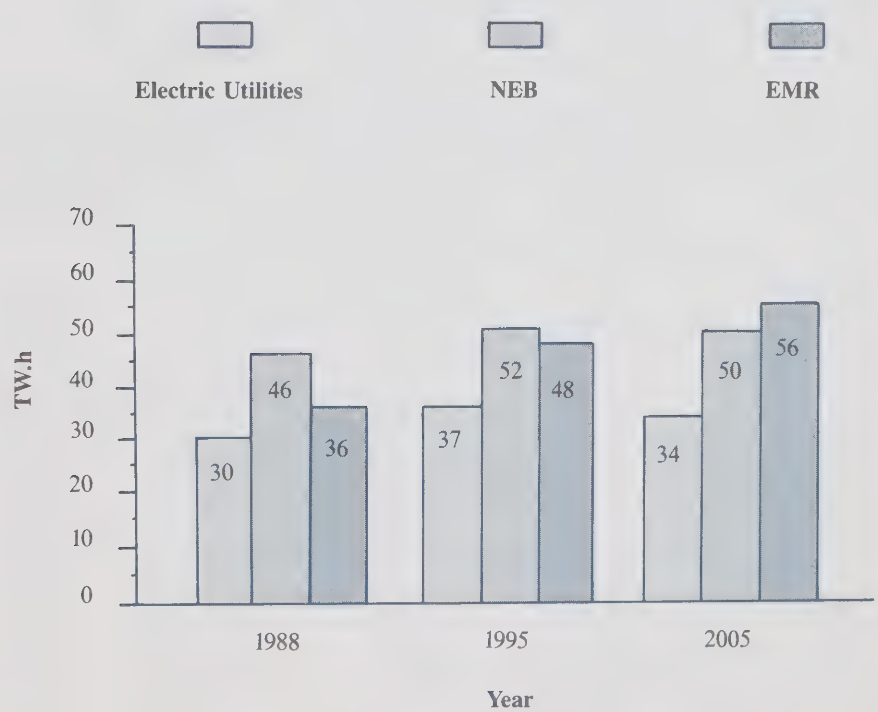
Canada and the United States enjoy essentially free trade in electricity: there is little direct government involvement in the contracting process, there are no tariffs, and there is a minimum of regulation. Table 12.10 reports projected electricity exports to the United States by province for the period 1987-2005. A comparison of electricity export forecasts is shown in Figure 12.4.

Table 12.10. Electricity exports to the United States

	1987	1990	1995	2000	2005
			(GW.h)		
New Brunswick	5 910	6 431	4 429	6 182	6 727
Quebec	16 400	15 980	19 515	18 184	17 805
Ontario	7 194	6 016	9 500	8 500	8 000
Manitoba	3 314	2 238	3 460	4 862	1 255
Saskatchewan	55	88	88	88	88
British Columbia	12 486	327	327	327	327
Canada	45 359	30 992	37 319	38 143	34 202

Source: Canadian electric utilities.

Figure 12.4. Comparison of electricity export forecasts



13. Hydroelectric Power Potential in Canada

INTRODUCTION

The harnessing of water power to generate electricity in Canada dates back to 1882, when a generating facility was installed at Chaudière Falls on the Ottawa River to provide electric lighting for a local sawmill.

With the establishment of the first Canadian commercial electric power company in Pembroke, Ontario, in 1884, the country's vast hydraulic resources immediately assumed new significance and, by 1890, electricity generated from water power was being distributed in a number of towns in Quebec and Ontario.

The subsequent development of hydroelectric power was facilitated by significant technical advances that took place around the turn of the century. Alternating current displaced direct current as the medium for power transmission, and the development of the hydraulic speed governor made parallel generation and integrated power systems possible. Developments in protection and control technology improved system reliability and safety. And long-distance transmission became possible, following the development of the electric transformer.

By 1900, every province except Prince Edward Island and Saskatchewan could boast of hydroelectric plants. These were modest in size, however; only Quebec, Ontario, and Nova Scotia had total capacities exceeding 10 MW. Canada's total installed hydraulic capacity at that time was 133 MW. By 1910, it had increased more than fivefold to 700 MW as electric power reached more urban centres.

The mineral and pulp and paper industries accounted for most of the installed generating capacity between 1910 and 1920, but new uses for electrical energy were appearing, such as for gold dredging in the Yukon and irrigation in British Columbia. By 1920, Canada's total hydroelectric generating capacity had reached almost 2000 MW. Although a few private industries and municipalities still chose to produce power for their own use, the desire to capitalize on economies of scale now began to encourage the development of large generating and distribution networks operated as public utilities.

By 1930, total Canadian generating capacity had more than doubled to 4700 MW. The Depression of the 1930s did not affect the electric power industry as much as it did other industries in Canada, but generally poor economic conditions accompanied by reduced demand resulted in a reduction in the installation rate during the period 1935-39. By the outbreak of World War II, Canada's generating capacity had grown to about 6700 MW, with the pulp and paper industry alone consuming more than 40 per cent of all energy generated.

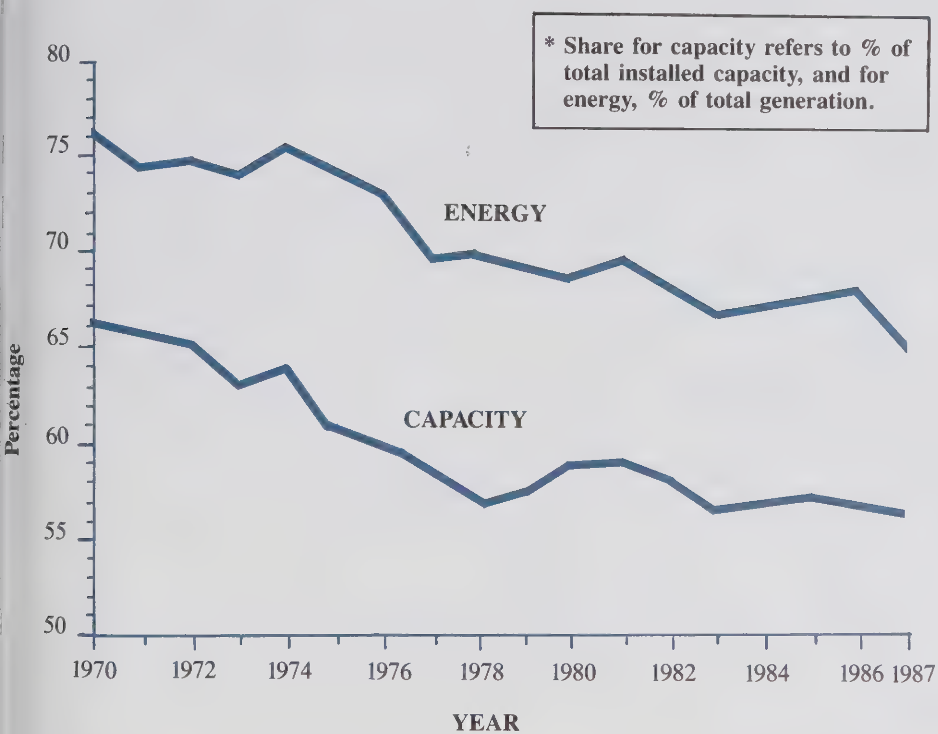
After the war, electricity demand continued to grow steadily. In 1950,

Table 13.1. Hydroelectric capacity and energy, 1970-1987

Year	Total (MW)	Hydro (MW)	Hydro (%)	Total (GW.h)	Hydro (GW.h)	Hydro (%)
1970	42 826	28 298	66.1	204 723	156 709	76.5
1971	46 678	30 601	65.6	215 064	160 412	74.6
1972	49 948	32 517	65.1	237 408	177 892	74.9
1973	54 271	34 266	63.1	262 139	192 868	73.6
1974	57 480	36 779	64.0	279 038	210 227	75.3
1975	61 352	37 282	60.8	273 392	202 396	74.0
1976	65 993	39 488	59.8	293 367	213 049	72.6
1977	70 575	40 810	57.8	316 549	220 150	69.5
1978	73 918	41 898	56.7	335 654	234 034	69.7
1979	77 228	44 009	57.0	352 304	243 041	69.0
1980	81 599	47 770	58.5	367 306	251 217	68.4
1981	83 308	49 216	59.1	377 622	262 253	69.4
1982	85 511	50 007	58.5	375 449	255 136	68.0
1983	89 492	51 274	57.3	395 005	262 862	66.5
1984	95 189	54 949	57.7	424 608	283 138	66.7
1985	97 020	57 711	59.5	447 182	301 250	67.4
1986	99 809	57 711	57.8	455 795	307 593	67.5
1987	100 638	57 711	57.3	482 108	313 159	65.0

Source: Energy, Mines and Resources Canada.

Figure 13.1. Hydroelectric capacity and energy shares *



total generating capacity in Canada was about 9800 MW, 91 per cent of which was provided from hydraulic sources. By 1970, total capacity had jumped to almost 43 000 MW, although the hydro share had fallen to 66.1 per cent. By 1980, capacity had doubled to 81 599 MW, and hydro's share had again fallen — to 58.5 per cent. This share has been more or less constant ever since. In 1987, total Canadian capacity was slightly more than 100 000 MW, and hydro's share was 57.3 per cent (see Table 13.1 and Figure 13.1).

HYDROELECTRIC POTENTIAL

Today, there is still a large amount of undeveloped hydroelectric potential in Canada. Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain, or because of environmental concerns, it is anticipated that a significant amount will be developed over the next 20 to 25 years. The provinces of Quebec, British Columbia, Manitoba, and Newfoundland

Table 13.2. Hydroelectric capacity in Canada, 1987

Province or Territory	In-Operation and Under Construction	Remaining Potential: Gross	Remaining Potential: Identified	Remaining Potential: Planning
	(MW)			
Newfoundland	6 652	5 201	4 623	4 623
Prince Edward Island	-	-	-	-
Nova Scotia	403	8 499	8 499	0
New Brunswick	903	780	440	440
Quebec	28 805	70 529	39 313	17 912
Ontario	7 807	12 387	4 238	2 911
Manitoba	4 921	8 190	5 090	5 090
Saskatchewan	830	2 189	935	935
Alberta	734	18 813	9 762	1 923
British Columbia	10 848	31 513	16 544	10 255
Yukon	82	11 699	10 938	3 088
Northwest Territories	50	9 224	9 196	2 446
Canada	62 035	179 024	109 578	49 623

Source: Canadian electrical utilities and Energy, Mines and Resources Canada.

account for most of the remaining river potential. Tidal resources are located in Nova Scotia, Quebec, and British Columbia.

Estimates of the remaining undeveloped hydro potential can be divided into three categories (see Table 13.2). The *gross remaining potential*, some 179 000 MW, is the estimated resource that remains undeveloped. Thus, including the sites now in-operation or under construction (about 62 000 MW), Canada's total hydroelectric resource is estimated to be some 241 000 MW. The *identified potential* consists of sites for which future development has been identified as technically feasible. This category totals about 110 000 MW and may include sites that are unlikely to be developed due to unfavourable economics or overriding environmental considerations. Finally, the *planning potential*, about 50 000 MW, comprises sites that are considered to be likely candidates for future development. Approximately 20 000 MW of this planning potential falls into the low-head (less than 40 m) category.

Estimates of the total gross, identified, and planning potential in Canada, as well as a listing of all the sites in each category and their capacity factors, are provided in Appendix C. Research on the assessment of Canada's remaining hydroelectric potential has not been carried out in depth in all provinces; the data provided in Appendix C should therefore be regarded as no more than preliminary estimates.

As shown in Table 13.2, British Columbia, Manitoba, Quebec, Newfoundland, and the two territories have large remaining hydroelectric river resources. Alberta and Saskatchewan have relatively modest remaining potential. Nova Scotia, New Brunswick, and Ontario have already developed the major portions of their hydroelectric river resources, and Prince Edward Island is unique in possessing virtually no such resources.

The most feasible Canadian tidal power resource is in the Bay of Fundy, with a total potential generating capacity of 8400 MW, at three sites (Minas Basin - 5338 MW, Cumberland Basin - 1428 MW, and Shepody Bay - 1643 MW). Of these sites, Cumberland Basin lies between New Brunswick and Nova Scotia; the others are in Nova Scotia. The tidal resource at Ungava Bay in Quebec is estimated to be 26 000 MW, although the distance from Quebec's load centres makes the Ungava potential unlikely to be developed in the foreseeable future. British Columbia's tidal resources are estimated at 716 MW (Observatory Inlet - 662 MW, and Sechelt Inlet - 54 MW). As noted above, the only existing tidal power installation in North America is the 20-MW Annapolis station in Nova Scotia.

Ontario Hydro researchers demonstrate the use of a "fish pulsar" in repelling shad. Ontario Hydro pioneered the design, which uses sound to guide fish away from water intakes to areas of safe passage.

A Hydro-Québec employee carries out line maintenance high above the St. Lawrence River near Ile d'Orléans.

APPENDIX A

Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1987

Year	Installed Capacity: Thermal: Conventional	Nuclear	Sub-Total	Hydro	Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin		Load Factor
	(MW)					(GW.h) (a)	(MW) (b)	(MW) (c)	(MW) (d)	(%)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960	4 392	-	4 392	18 657	23 049	109 302	12 477	17 264	5 785	34	72
1965	7 557	20	7 577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 527	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980	27 853	5 866	33 719	47 919	81 638	340 069	38 821	59 170	22 464	38	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984r	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985r	30 885	9 813	40 698	56 048	96 746	406 038	46 351	71 309	25 437	34	65
1986r	30 980	11 098	42 078	57 731	99 809	421 817	48 153	70 314	29 495	42	68
1987p	31 084	11 928	43 012	57 731	100 743	438 152	50 017	74 302	26 441	36	67

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy for sale, to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81: Statistics Canada Publication, 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr).

(c) Statistics Canada Publication 57-204.

(d) Reserve margin = $\dfrac{\text{(Installed capacity − Peak demand)}}{\text{Peak demand}}$

(e) Load Factor = Average demand ÷ Peak demand.

p Preliminary figures. r Revised figures.

Source: Statistics Canada.
Energy, Mines and Resources Canada.

Table A2. Installed and proposed generating capacity, 1987

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	(MW)				
Newfoundland	6 644	0	758	7 402	7.36
Prince Edward Island	0	0	122	122	.12
Nova Scotia	386	0	1 960	2 346	2.33
New Brunswick	903	680	1 907	3 490	3.47
Quebec	25 849	685	1 110	27 644	27.47
Ontario	7 764	10 563	13 796	32 123	31.92
Manitoba	3 641	0	496	4 137	4.11
Saskatchewan	830	0	2 118	2 948	2.93
Alberta	734	0	6 871	7 605	7.56
British Columbia	10 848	0	1 660	12 508	12.43
Yukon	82	0	41	123	.12
Northwest Territories	50	0	140	190	.19
Canada (Totals as of December 31, 1987)	57 731	11 928	30 979	100 638	100.00
Percentage of total	57.37	11.85	30.78	100.00	
Net additions during 1987	0	830	4	834	
Planned additions, 1988	8	0	137	145	

Source: Energy, Mines and Resources Canada.

Table A3. Conventional thermal capacity by principal fuel type* (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other**	Total
Nfld.	0	505	0	0	505	170	0	170	83	0	83	0	758	0	0	758
P.E.I.	0	70	0	0	70	41	0	41	11	0	11	0	122	0	0	122
N.S.	954	800	0	0	1 754	205	0	205	1	0	1	954	1 006	0	0	1 960
N.B.	285	1 561	0	22	1 868	23	0	23	16	0	16	285	1 600	0	22	1 907
Que.	0	628	0	10	638	363	0	363	109	0	109	0	1 100	0	10	1 110
Ont.	9 511	2 200	1 362	90	13 163	469	155	624	4	6	10	9 511	2 673	1 523	90	13 797
Man.	419	0	4	23	446	24	0	24	26	0	26	419	50	4	23	496
Sask.	1 772	0	141	43	1 956	0	155	155	7	0	7	1 772	7	296	43	2 118
Alta.	4 479	65	1 648	107	6 299	0	524	524	15	33	48	4 479	80	2 205	107	6 871
B.C.	0	126	1 038	247	1 411	100	54	154	78	17	95	0	304	1 109	247	1 660
Yukon	0	0	0	0	0	0	0	0	41	0	41	0	41	0	0	41
N.W.T.	0	0	0	0	0	0	20	20	120	0	120	0	120	20	0	140
Canada	1 7 420	5 955	4 193	542	28 110	1 395	908	2 303	511	56	567	17 420	7 861	5 157	542	30 980

* *Preliminary figures as of December 31, 1987.*
** *Mainly wood wastes and black liquor.*
Numbers may not total due to rounding.

Source: Electrical Energy Branch,
Energy, Mines and Resources Canada.

Table A4. Electrical energy production by principal fuel type, 1987

	Conventional Thermal*							% of Total	% Generated By	
	Coal	Oil	Gas	Total	Nuclear	Hydro	Total	Generation	Utilities	Industry
	(GW.h)									
Newfoundland	0	2 317	0	2 317	0	37 773	40 090	8.32	99.03	.97
Prince Edward Island	108	56	0	164	0	0	164	.03	34.15	65.85
Nova Scotia	5 436	1 539	0	6 975	0	774	7 749	1.61	95.48	4.52
New Brunswick	1 452	3 710	0	5 162	5 112	2 219	12 493	2.59	95.27	4.73
Quebec	0	182	0	182	4 660	152 110	156 952	32.56	89.52	10.48
Ontario	32 291	47	1 524	33 862	63 116	34 604	131 582	27.29	97.23	2.77
Manitoba	577	7	7	591	0	19 311	19 902	4.13	99.74	.26
Saskatchewan	8 931	12	309	9 252	0	3 188	12 440	2.58	97.12	2.88
Alberta	30 514	130	4 676	35 320	0	1 450	36 770	7.63	90.87	9.13
British Columbia	961	470	579	2 010	0	61 057	63 067	13.08	81.54	18.46
Yukon	0	23	0	23	0	409	432	.09	100.00	.00
N.W.T.	0	173	0	173	0	294	467	.10	94.22	5.78
Canada	80 270	8 666	7 095	96 031	72 888	313 189	482 108	100.00	89.51	10.49

** The conventional thermal breakdown is estimated.*

Source: Statistics Canada.
Energy, Mines and Resources Canada.

Table A5. Provincial electricity imports and exports (GW.h)

Province	Year	Interprovincial Trade			International Trade*			Total Net
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	Exports
Newfoundland	1987	30 393	-	30 393	-	-	-	30 393
	1986	30 695	-	30 695	-	-	-	30 695
	1985	31 837	-	31 837	-	-	-	31 837
	1984	36 043	-	36 043	-	-	-	36 043
	1983	31 234	-	31 234	-	-	-	31 234
Prince Edward Island	1987	-	483	-483	-	-	-	-483
	1986	-	610	-610	-	-	-	-610
	1985	-	575	-575	-	-	-	-575
	1984	-	539	-539	-	-	-	-539
	1983	-	519	-519	-	-	-	-519
Nova Scotia	1987	82	659	-577	-	-	-	-577
	1986	71	611	-540	-	-	-	-540
	1985	199	350	-151	-	-	-	-151
	1984	282	301	-19	-	-	-	-19
	1983	121	723	-602	-	-	-	-602
New Brunswick	1987	1 164	6 922	-5 758	6 141	266	5 875	117
	1986	1 230	7 275	-6 045	7 008	424	6 584	539
	1985	927	6 026	-5 099	6 093	12	6 081	982
	1984	841	4 588	-3 747	5 657	17	5 640	1 893
	1983	1 245	4 112	-2 867	5 265	24	5 241	2 374
Quebec	1987	12 782	30 427	-17 645	16 401	-	16 401	-1 244
	1986	14 496	30 712	-16 216	12 674	35	12 639	-3 577
	1985	14 491	31 878	-17 387	9 581	3	9 578	-7 809
	1984	11 668	36 105	-24 437	11 250	8	11 242	-13 195
	1983	9 371	31 290	-21 919	10 128	8	10 120	-11 799
Ontario	1987	16	6 992	-6 976	8 497	2 113	6 384	-592
	1986	22	8 027	-8 005	7 957	1 693	6 264	-1 441
	1985	44	9 632	-9 588	10 563	1 701	8 862	-726
	1984	64	8 302	-8 238	11 370	913	10 457	2 219
	1983	59	6 336	-6 277	12 207	369	11 838	5 561
Manitoba	1987	2 311	1 220	1 091	3 461	512	2 949	4 040
	1986	1 946	1 087	859	6 989	12	6 977	7 836
	1985	2 524	1 238	1 286	5 660	45	5 615	6 901
	1984	2 565	1 301	1 264	5 057	43	5 014	6 278
	1983	2 555	1 213	1 342	5 994	19	5 975	7 317

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Table A5. Provincial electricity imports and exports (GW.h) (Continued)

Province	Year	Interprovincial Trade			International Trade*			Total Net Exports
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	
Saskatchewan	1987	1 222	1 262	-40	113	84	29	-11
	1986	1 076	1 210	-134	151	64	87	-47
	1985	1 236	1 556	-320	163	93	70	-250
	1984	1 302	1 625	-323	86	66	20	-303
	1983	1 210	1 601	-391	81	84	-3	-394
Alberta	1987	710	526	184	-	2	-2	182
	1986	617	555	62	-	3	-3	59
	1985	243	278	-35	-	2	-2	-37
	1984	262	302	-40	-	2	-2	-42
	1983	198	346	-148	-	2	-2	-150
British Columbia	1987	521	710	-189	12 815	493	12 322	12 133
	1986	553	617	-64	4 156	2 727	1 429	1 365
	1985	275	243	32	10 956	837	10 119	10 151
	1984	298	262	36	8 015	1 294	6 721	6 757
	1983	341	196	145	4 633	2 251	2 382	2 527
Yukon	1987	-	-	-	-	-	-	-
	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
Northwest Territories	1987	-	-	-	-	-	-	-
	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
	1984	-	-	-	-	-	-	-
	1983	-	-	-	-	-	-	-
Canada	1987	-	-	-	47 428	3 470	43 958	43 958
	1986	-	-	-	38 934	4 957	33 977	33 977
	1985	-	-	-	43 016	2 693	40 323	40 323
	1984	-	-	-	41 436	2 343	39 093	39 093
	1983	-	-	-	38 308	2 757	35 551	35 551

* *Includes exchanges.*

Source: Statistics Canada.

Table A6. Electricity exports by utility, 1987

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
Fraser Inc.	Maine	16 484	378
Maine & New Brunswick Electrical Power Co. Ltd.	Maine	1 354	72
N.B. Power	Maine	139 764	3 646
N.B. Power	Massachusetts	120 431	1 813
Hydro-Québec	Maine	47	1
Hydro-Québec	Vermont	70 648	1 914
Hydro-Québec	NEPOOL	136 241	4 773
Hydro-Québec	New York	238 410	9 712
St. Lawrence Power Co.	New York	6 742	282
Ontario Hydro	Vermont	10 401	264
Ontario Hydro	New York	158 079	5 420
Ontario Hydro	Michigan	22 459	807
Ontario Hydro	Minnesota	113	3
Canadian Niagara Power Co.	New York	14 774	418
Boise Cascade Canada Ltd.	Minnesota	5	N
Manitoba Hydro	Minnesota	51 083	2 561
Manitoba Hydro	North Dakota	14 342	753
SaskPower	North Dakota	168	55
Cominco Ltd.	Washington	2 370	152
Cominco Ltd.	Oregon	3 024	176
Cominco Ltd.	Idaho	67	4
Cominco Ltd.	Montana	339	24
Cominco Ltd.	California	8 886	484
Cominco Ltd.	Nevada	111	7
Cominco Ltd.	Utah	22	2

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Table A6. Electricity exports by utility, 1987 (Continued)

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
West Kootenay Power	Washington	1	N
B.C. Hydro	Washington	27 924	1 530
B.C. Hydro	Oregon	62 638	4 481
B.C. Hydro	Idaho	614	37
B.C. Hydro	Montana	67	4
B.C. Hydro	California	99 631	5 537
B.C. Hydro	Nevada	166	12
B.C. Hydro	Utah	498	35
B.C. Hydro	Alaska	64	N

N = negligible

Source: Energy, Mines and Resources Canada.

Table A7. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1986	504.60	170.39	82.81	.00	757.80	6 643.80	7 401.60
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	504.60	170.39	82.81	.00	757.80	6 643.80	7 401.60
Additions proposed							
1988	25.00	-	-	-	25.00	8.00	33.00
1989	25.00	-	-	-	25.00	-	25.00
1990	-	108.00	-	-	108.00	-	108.00
1991	-	-	-	-	.00	30.00	30.00
1992	-	54.00	-	-	54.00	-	54.00
2003	-	54.00	-	-	54.00	-	54.00
2004	-	54.00	-	-	54.00	-	54.00
Total end 2004	554.60	440.39	82.81	.00	1 077.80	6 681.80	7 759.60
PRINCE EDWARD ISLAND							
Total end 1986	70.50	40.85	11.14	.00	122.49	.00	122.49
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	70.50	40.85	11.14	.00	122.49	.00	122.49
NOVA SCOTIA							
Total end 1986	1 753.79	205.00	0.60	.00	1 959.39	386.36	2 345.75
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	1 753.79	205.00	0.60	.00	1 959.39	386.36	2 345.75
Additions proposed							
1991	150.00	-	-	-	150.00	-	150.00
1993	150.00	-	-	-	150.00	-	150.00
1994	300.00	-	-	-	300.00	-	300.00
1995	150.00	-	-	-	150.00	-	150.00
1998	300.00	-	-	-	300.00	-	300.00
2001	150.00	-	-	-	150.00	-	150.00
2003	300.00	-	-	-	300.00	-	300.00
Total end 2003	3 253.79	205.00	0.60	.00	3 459.39	386.36	3 845.75
NEW BRUNSWICK							
Total end 1986	1 868.08	23.38	16.34	680.00	2 587.80	903.03	3 490.83
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	1 868.08	23.38	16.34	680.00	2 587.80	903.03	3 490.83
Additions proposed							
1993	400.00	-	-	-	400.00	-	400.00
1995	200.00	-	-	-	200.00	-	200.00
1998	400.00	-	-	-	400.00	-	400.00
Total end 1998	2 868.08	23.38	16.34	680.00	3 587.80	903.03	4 490.83

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
QUEBEC							
Total end 1986	371.35	362.88	109.18	685.00	1 528.41	25 848.91	27 377.32
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	371.35	362.88	109.18	685.00	1 528.41	25 848.91	27 377.32
Additions proposed							
1989	-	-	-	-	.00	1 056.00	1 056.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	-	.00	-	.00
1992	-	-	-	-	.00	950.00	950.00
1993	-	-	-	-	.00	950.00	950.00
1994	-	-	-	-	.00	-	.00
1995	-	-	-	-	.00	1 431.00	1 431.00
1996	-	-	-	-	.00	1 033.00	1 033.00
1997	-	-	-	-	.00	500.00	500.00
1998	-	-	-	-	.00	822.00	822.00
1999	-	-	-	-	.00	1 187.00	1 187.00
2000	-	-	-	-	.00	791.00	791.00
2001	-	-	-	-	.00	913.00	913.00
2002	-	-	-	-	.00	219.00	219.00
2003	-	-	-	-	.00	601.00	601.00
2004	-	-	-	-	.00	775.00	775.00
2005	-	372.00	-	-	372.00	249.00	621.00
2006	-	-	-	-	.00	621.00	621.00
Total end 2006	371.35	734.88	109.18	685.00	1 900.41	37 946.91	37 850.32
ONTARIO							
Total end 1986	13 162.49	623.57	9.52	9 733.00	23 528.58	7 763.60	31 292.18
Additions 1987	-	-	-	830.00	830.00	-	830.00
Total end 1987	13 162.49	623.57	9.52	10 563.00	24 358.58	7 763.60	32 122.18
Additions proposed							
1988	-	104.00	-	-	104.00	-	104.00
1989	-	-	-	1 762.00	1 762.00	43.00	1 805.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	881.00	881.00	-	881.00
1992	-	-	-	881.00	881.00	-	881.00
Total end 1992	13 162.49	727.57	9.52	14 087.00	27 986.58	7 806.60	35 793.18

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
MANITOBA							
Total end 1986	445.80	23.80	26.44	-	496.04	3 641.10	4 137.14
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	445.80	23.80	26.44	.00	496.04	3 641.10	4 137.14
Additions proposed							
1990	-	-	-	-	.00	256.00	256.00
1991	-	-	-	-	.00	640.00	640.00
1992	-	-	-	-	.00	384.00	384.00
1999	-	-	-	-	.00	260.00	260.00
2000	-	-	-	-	.00	390.00	390.00
2001	-	-	-	-	.00	650.00	650.00
2012	-	-	-	-	.00	87.50	87.50
2013	-	-	-	-	.00	262.50	262.50
Total end 2013	445.80	23.80	26.44	.00	496.04	6 571.10	7 067.14
SASKATCHEWAN							
Total end 1986	1 956.76	154.92	6.60	.00	2 118.28	830.00	2 948.28
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	1 956.76	154.92	6.60	.00	2 118.28	830.00	2 948.28
Additions proposed							
1990	-	100.00	-	-	100.00	-	100.00
1991	-	50.00	-	-	50.00	-	50.00
1992	-	50.00	-	-	50.00	-	50.00
Total end 1992	1 956.76	354.92	6.60	.00	2 318.28	830.00	3 148.28
ALBERTA							
Total end 1986	6 298.22	524.10	48.28	.00	6 870.60	733.70	7 604.30
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	6 298.22	524.10	48.28	.00	6 870.60	733.70	7 604.30
Additions proposed							
1989	400.00	-	-	-	400.00	-	400.00
1991	400.00	-	-	-	400.00	-	400.00
1994	-	200.00	-	-	200.00	-	200.00
1995	375.00	-	-	-	375.00	-	375.00
1996	375.00	100.00	-	-	475.00	-	475.00
1997	375.00	-	-	-	375.00	-	375.00
1998	-	400.00	-	-	400.00	-	400.00
1999	375.00	100.00	-	-	475.00	-	475.00
2000	375.00	300.00	-	-	675.00	-	675.00
2001	375.00	-	-	-	375.00	-	375.00
2003	750.00	100.00	-	-	850.00	-	850.00
2004	375.00	-	-	-	375.00	-	375.00
Total end 2004	10 473.22	1 724.10	48.28	.00	12 245.60	733.70	12 979.30

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Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
BRITISH COLUMBIA							
Total end 1986	1 411.42	153.70	92.25	.00	1 660.37	10 847.87	12 508.24
Additions 1987	-	-	-	-	.00	-	.00
Total end 1987	1 411.42	153.70	92.25	.00	1 660.37	10 847.87	12 508.24
Additions proposed							
2000	-	-	-	-	.00	300.00	300.00
2001	-	-	-	-	.00	760.00	760.00
2002	-	-	-	-	.00	80.00	80.00
2003	-	-	-	-	.00	-	.00
2004	-	-	-	-	.00	110.00	110.00
2005	500.00	-	-	-	500.00	110.00	610.00
2006	500.00	-	-	-	500.00	55.00	555.00
2007	500.00	-	-	-	500.00	-	500.00
2008	500.00	-	-	-	500.00	-	500.00
Total end 2008	3 411.42	153.70	95.25	.00	3 660.37	12 262.87	15 923.24
YUKON and N.W.T.							
Total end 1986	.00	19.50	161.41	.00	180.91	131.70	312.61
Additions 1987	-	-	4.10	-	4.10	-	4.10
Total end 1987	.00	19.50	165.51	.00	185.01	131.70	316.71
Additions proposed							
1988	-	-	8.20	-	8.20	-	8.20
1989	-	-	1.60	-	1.60	-	1.60
1990	-	-	1.70	-	1.70	-	1.70
1991	-	-	1.70	-	1.70	-	1.70
1992	-	-	2.40	-	2.40	-	2.40
1993	-	-	1.20	-	1.20	-	1.20
1994	-	-	.50	-	.50	-	.50
Total end 1994	.00	19.50	182.81	.00	202.31	131.70	334.01

Table A7. Generation capacity by type (MW) (Continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
CANADA							
Total end 1986	27 843.01	2 302.09	567.57	11 098.00	41 810.67	57 730.07	100 298.54
Additions 1987	-	-	4.10	830.00	834.10	-	834.10
Total end 1987	27 843.01	2 302.09	571.67	11 928.00	42 644.77	57 730.07	101 132.64
Additions proposed							
1988	25.00	104.00	8.20	-	137.20	8.00	145.20
1989	425.00	-	1.60	1 762.00	2 188.60	1 099.00	3 287.60
1990	-	208.00	1.70	-	209.70	256.00	465.70
1991	550.00	50.00	1.70	881.00	1 482.70	670.00	2 152.70
1992	-	104.00	2.40	881.00	987.40	1 334.00	2 321.40
1993	550.00	-	1.20	-	551.20	950.00	1 501.20
1994	300.00	200.00	.50	-	500.50	-	500.50
1995	725.00	-	-	-	725.00	1 431.00	2 156.00
1996	375.00	100.00	-	-	475.00	1 033.00	1 508.00
1997	375.00	-	-	-	375.00	500.00	875.00
1998	700.00	400.00	-	-	1 100.00	822.00	1 922.00
1999	375.00	100.00	-	-	475.00	1 447.00	1 922.00
2000	375.00	300.00	-	-	675.00	1 481.00	2 156.00
2001	525.00	-	-	-	525.00	2 323.00	2 848.00
2002	-	-	-	-	.00	299.00	299.00
2003	1 050.00	154.00	-	-	1 204.00	601.00	1 805.00
2004	375.00	54.00	-	-	429.00	885.00	1 314.00
2005	500.00	372.00	-	-	872.00	359.00	1 231.00
2006	500.00	-	-	-	500.00	676.00	1 176.00
2007	500.00	-	-	-	500.00	-	500.00
2008	500.00	-	-	-	500.00	-	500.00
2012	-	-	-	-	.00	87.50	87.50
2013	-	-	-	-	.00	262.50	262.50
Total end 2013	36 568.01	4 448.09	588.97	15 452.00	57 057.07	74 254.07	131 311.14

Source: Energy, Mines and Resources Canada.

Table A8. Installed generating capacity expansion in Canada by station. Major 1987 additions and 1988 - 2013 projections

Province and Station	Type*	1987 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Holyrood[1]	S(o)		1988	25	P	
			1989	25	P	500
Paradise River	H		1988	8	C	8
Stephenville	GT(o)		1990	54	P	108
Hardwoods	GT(o)		1990	54	P	108
Island Pond	H		1991	30	C	30
Undecided	GT(o)		1992	54	P	
			2003	54	P	
			2004	54	P	
NOVA SCOTIA						
New Coal "A"	S(c)		1993	150	C	
			1995	150	P	
			2001	150	P	450
New Coal "B"	S(c)		1994	300	P	
			1998	300	P	
			2003	300	P	900
Trenton	S(c)		1991	150	C	360
NEW BRUNSWICK						
New Steam	S(c)		1993	400	P	
			1998	400	P	800
Grand Lake	S(c)		1995	200	P	285

[1] Uprating of exising units.

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Table A8. Installed generating capacity expansion in Canada by station. Major 1987 additions and 1988 - 2013 projections (Continued)

Province and Station	Type*	1987 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC						
La Forge-1	H		1995	5 × 130	P	
			1995	133	P	783
La Forge-2	H		2003	3 × 90	P	270
Manic-3A	H		1997	2 × 250	P	500
Manic-5A	H		1989	4 × 264	C	1 056
Brisay	H		1996	193	P	
			1996	192	P	385
LG-1	H		1995	6 × 108	P	
			1996	6 × 108	P	1 296
LG-2A	H		1992	2 × 317	P	
			1992	316	P	
			1993	2 × 317	P	
			1993	316	P	1 900
Ste-Marguerite	H		1998	2 × 411	P	822
Grande Baleine-1	H		1999	2 × 396	P	
			1999	395	P	
			2000	396	P	
			2000	395	P	1 978
Grande Baleine-2	H		2001	154	P	
			2001	2 × 153	P	460
Grande Baleine-3	H		2001	3 × 151	P	453
Ashuapmushuan-3	H		2003	111	P	
			2003	2 × 110	P	331
Ashuapmushuan-4	H		2002	109	P	
			2002	110	P	219
Eastmain-1	H		2004	3 × 170	P	510
Quenonisca	H		2004	5 × 53	P	265
Broadback-8	H		2005	124	P	
			2005	125	P	
			2006	4 × 124	P	
			2006	125	P	870
Future peaking	GT(d)		2005	372	P	372
ONTARIO						
Bruce B	N	830			I	3 320
Darlington	N		1989	2 × 881	C	
			1991	881	C	
			1992	881	C	
	GT		1988	4 × 26	C	3 628
Magpie	H		1989	4 × 7.5	P	
			1989	2 × 6.5	P	43

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Table A8. Installed generating capacity expansion in Canada by station. Major 1987 additions and 1988 - 2013 projections (Continued)

Province and Station	Type*	1987 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
MANITOBA						
Limestone	H		1990	2 × 128	C	
			1991	5 × 128	C	
			1992	3 × 128	C	1 280
Conawapa	H		1999	2 × 130	P	
			2000	3 × 130	P	
			2001	5 × 130	P	1 300
Wuskwatim	H		2012	87.5	P	
			2013	3 × 87.5	P	350
SASKATCHEWAN						
Shand	S(c)		1992	300	C	300
Future peaking 1	GT(g)		1990	50	P	50
Future peaking 2	GT(g)		1990	50	P	50
Future peaking 3	GT(g)		1991	50	P	50
ALBERTA						
Genesee	S(c)		1989	400	C	
			1991	400	C	800
Sheerness	S(c)		1990	380	C	760
New Steam	S(c)		1995	375	P	
			1996	375	P	
			1997	375	P	
			1999	375	P	
			2000	375	P	
			2001	375	P	
			2003	2 × 375	P	
			2004	375	P	3 375
Peak Gas	GT		1994	2 × 100	P	
			1996	100	P	
			1998	4 × 100	P	
			1999	100	P	
			2000	3 × 100	P	
			2003	100	P	1 200

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Table A8. Installed generating capacity expansion in Canada by station. Major 1987 additions and 1988 - 2013 projections (Continued)

Province and Station	Type*	1987 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
BRITISH COLUMBIA						
Keenleyside	H		2001	2 × 80	P	
			2002	80	P	240
Peace Site C	H		2000	2 × 150	P	
			2001	4 × 150	P	900
Murphy Creek	H		2004	2 × 55	P	
	H		2005	2 × 55	P	
			2006	55	P	275
Hat Creek	S(c)		2005	500	P	
			2006	500	P	
			2007	500	P	
			2008	500	P	2 000
YUKON						
Dawson	IC	1				3.4
NORTHWEST TERRITORIES						
Various	IC	3.1				
			1988	8.2	P	
			1989	1.6	P	
			1990	1.7	P	
			1991	1.7	P	
			1992	2.4	P	
			1993	1.2	P	
			1994	0.5	P	

* **Legend**

H	*Hydro*	*IC*	*Internal combustion*
S(c)	*Steam (coal)*	*GT*	*Gas turbine*
S(o)	*Steam (oil)*	*I*	*Installed*
N	*Nuclear*	*C*	*Under construction*
P	*Planned*		
GT(o)	*Gas turbine (oil)*		
GT(G)	*Gas turbine (natural gas)*		

Source: Energy, Mines and Resources Canada.

APPENDIX B

B1. Chronology of Canadian Electrical Energy Developments and Achievements

1846 Toronto, Hamilton, Niagara, and St. Catharines Electro-Magnetic Telegraph Company formed.

1847 Montreal Telegraph Company formed with lines from Quebec City to Toronto.

1858 Message sent from Queen Victoria to U.S. President Buchanan via first trans-Atlantic cable from Valentia, Ireland, to White Sands Bay, Newfoundland.

1873 Davis House in Winnipeg used arc light to illuminate front of building.

1876 Alexander Graham Bell made first long-distance telephone call from Paris, Ontario, to Brantford, Ontario, via battery power in Toronto — a total distance of 218 km.

1878 Robert McMicking began experiments with electric street lighting in Victoria.

1878 American Electric and Illuminating Company formed in Montreal – Canada's first electric light company.

1879 British Columbia Electric Railway launched.

1879 Electric light demonstrated in McConkey's Restaurant, Toronto.

1881 Toronto's first electric generator built by J.J. White. T. Eaton was the first customer.

1881 Ahearn & Soper of Ottawa introduced electric light for industry.

1882 One of North America's first hydroelectric generating facilities constructed at Chaudière Falls on the Ottawa River.

1882 F. Nicholls formed Toronto Electric Supply Company (forerunner of Canadian General Electric).

1883 Canada's first electric lighting plant started at Canadian Cottons, Cornwall, Ontario, by Thomas Edison.

1883 Toronto's first electric railway built by J.J. Wright.

1883 Canada's first street lights installed in Hamilton, Ontario.

1884 Canada's first electric utility set up in Pembroke, Ontario, by R.B. McAllister.

1884 Electric street lighting installed in Montreal and Toronto.

1885 First Canadian electric streetcar enters service in Toronto.

1885 St. John's Electric Light Company produced power for street and shop lighting.

1886 Victoria Electric Lighting Company (forerunner of B.C. Electric and B.C. Hydro) formed.

1887 Hydroelectric plant built at Twelve Mile Creek, near Welland, Ontario.

1889 Calgary sawmill run by electricity; electric lights in Calgary, Brandon, and Winnipeg.

1890 Electric lights in Regina, Kenora, Portage la Prairie, and Moosejaw.

1891 Canadian Electrical Association formed.

1892 Canadian General Electric incorporated.

1892 Montreal's first hydroelectric plant established on the Lachine Canal.

1892 Canadian Niagara Power Company incorporated.

1892 Thomas L. "Carbide" Willson of Woodstock, Ontario, developed the electric-furnace process to manufacture calcium carbide.

1896 Marconi applied for a patent on wireless telegraphy.

1897 Hydroelectric power from Montmorency Falls supplies street lighting in Quebec City.

1897 Canadian branch of Westinghouse established at Hamilton.

1897 First long-distance, high-voltage transmission line (11 kV) carried power from St. Narcisse, to Trois-Rivières, Quebec — a distance of 29 km.

1898 Shawinigan Water & Power Company incorporated in Quebec.

1898 Royal Electric generated 15 MW at Chambly for transmission 26 km to Montreal.

1900 Hydroelectric power distributed in all provinces except Prince Edward Island and Saskatchewan.

1900 Montreal Light, Heat and Power Company formed.

1900 Canada's installed hydroelectric capacity reached 133 MW.

1901 Trans-Atlantic wireless demonstrated from Newfoundland by Marconi.

1902 Shawinigan aluminium plant produced conductors for the Shawinigan-Montreal transmission line.

1902 A communications cable between Canada and Australia — the Pacific Cable — was successfully completed. The Pacific Cable was developed by Canadian engineer Sir Sandford Fleming.

1903 Shawinigan Water & Power installed the world's largest generator (5,000 hp) and transmitted power over the world's longest and highest voltage line — 136 km to Montreal at 50 kV.

1904 First significant exchange of power with the United States initiated at Niagara Falls.

1905 Ontario Hydro established.

1906 Hydroelectric power transmitted 96 km from the Winnipeg River to Winnipeg.

1910 Canada's installed hydroelectric capacity reached 700 MW.

1910 First 110-kV transmission line built from Niagara Falls to Dundas, Ontario.

1910 Quebec Streams Commission established.

1918 New Brunswick Electric Power Commission created.

1918 Maritime Electric Company established.

1919 Ernest Rutherford of McGill University achieved atomic fission.

1919 Manitoba Power Commission established.

1919 Nova Scotia Power Commission established.

1921 Sir Adam Beck No.1 generating plant opened in Niagara Falls, then the largest in the world. Total capacity installed by 1924 was 528 MW.

1924 Newfoundland Light & Power Company established.

1929 Saskatchewan Power Corporation formed.

1930 Canada's installed generating capacity reached 4700 MW.

1944 Hydro-Québec formed; acquired the facilities of the Montreal Light, Heat and Power Company.

1948 The Northwest Territories Power Commission was created. In 1956, it was renamed the Northern Canada Power Commission.

1951 First 100-MW thermal generating unit installed.

1954 Newfoundland and Labrador Hydro created.

1956 First 315-kV transmission lines energized to carry power from Bersimis No.1 in northeastern Quebec to Quebec City and Montreal.

1957 First Canadian pumping/generating station (capacity 177 MW) enters service at Niagara Falls.

1958 Great Lakes Power Company installed highest head (34 m) variable pitch blade Kaplan turbine in North America.

1960 Beauharnois (Quebec) first generating station to exceed 1000 MW installed. By 1986, installed capacity at this station reached 1639 MW.

1961 First 300-MW thermal generating unit installed at Lakeview, Ontario.

1962 Saskatchewan Power installed first 25-kV underground residential distribution system.

1962 B.C. Hydro acquired the B.C. Electric Company.

1963 Hydro-Québec acquired private power companies, including Shawinigan Water & Power.

1965 First 735-kV transmission line from Manicouagan-Outardes to the Quebec load centres energized. At the time, it was the highest A.C. voltage in commercial use in the world.

1967 First commercial-scale (220 MW) CANDU nuclear generating station in service at Douglas Point, Ontario.

1967 Ontario Hydro completes a 696-km, 500-kV transmission line from James Bay generating statio to Toronto.

1968 Power from Peace River transmitted to the B.C. low mainland via a 918-km, 500-kV line.

1968 First Canadian D.C. transmission line in service between Vancouver Island and the mainland at 260 kV.

1969 First 500-MW thermal generating unit operating at Lambton, Ontario.

1971 First two of four 542-MW nuclear generating units commissioned at Pickering, Ontario.

1971 First two units (500 MW and 475 MW) of the Churchill Falls, Labrador, hydroelectric station commissioned.

1972 World's largest solid-state high-voltage, direct-curre (HVDC) converter/inverter terminal (320 MW) plac in service at Eel River, New Brunswick.

1972 An 880-km, 450-kV HVDC long-distance transmission system placed in commercial operatio from the Nelson River to Winnipeg.

1973 Nova Scotia Power Commission became Nova Sco Power Corporation, incorporating Nova Scotia Ligl & Power Company.

1974 Completion of the Churchill Falls generating statio with a total capacity of 5429 MW.

1976 First 825-MW unit of the Bruce nuclear generating complex commissioned. (Total capacity of the complex is now 6600 MW.)

1978 New Brunswick-P.E.I. 100-MW submarine cable interconnection placed in service.

1979 First four 333-MW units of the LG 2 (James Bay) hydroelectric station placed in service by Hydro-Québec. (Total station capacity is 5328 MW, achie by 1981.)

1983 Point Lepreau No.1 nuclear power unit (680 MW) placed in service by N.B. Power at Point Lepreau, New Brunswick.

1984 First tidal power generating plant in North Americ placed in service by Nova Scotia Power at Annapc Royal, Nova Scotia.

B2. Chronology of Regional Interconnections

Interconnection	Voltage (kV)	Date-in-Service
Quebec-Ontario	230	1928
Quebec-Ontario	115	1930 (1)
Quebec-Ontario	230	1932
Quebec-Ontario	115	1933 (1)
Quebec-Ontario	115	1940 (1)
Quebec-Ontario	230	1941
Quebec-Ontario	115	1942
Quebec-Ontario	115	1949
Quebec-Ontario	115	1949
Manitoba-Ontario	115	1956 (2)
Manitoba-Saskatchewan	230	1960
New Brunswick-Nova Scotia	138	1961
New Brunswick-Nova Scotia	138	1965
Quebec-New Brunswick	69	1965
Quebec-Ontario	115	1966
Quebec-Ontario	115	1966
Western Ontario-Eastern Ontario	230	1969
Labrador-Quebec	735	1971
Labrador-Quebec	735	1972
Western Ontario-Eastern Ontario	230	1972
Manitoba-Saskatchewan	230	1972
Manitoba-Ontario	230	1972
Quebec-New Brunswick	±80 (DC)	1972
Quebec-New Brunswick	230	1972
Manitoba-Ontario	230	1973
Labrador-Quebec	735	1973
Alberta-British Columbia	138	1973
New Brunswick-Nova Scotia	345	1976 (3)
New Brunswick-Prince Edward Island	138	1977 (4)
New Brunswick-Prince Edward Island	138	1977 (4)
Manitoba-Saskatchewan	230	1979
Alberta-British Columbia	500	1985
Quebec-New Brunswick	±80 (DC)	1985
Quebec-New Brunswick	345	1985

Notes: (1) 230-kV construction.
(2) Constructed in 1931; interconnected in 1956.
(3) Operated at 138 kV until 1979.
(4) Submarine cable.

All interconnections are alternating current (AC), except for the Quebec-New Brunswick direct current (DC) facilities.

All Quebec-Ontario interconnections and both Quebec-New Brunswick AC interconnections are radial (i.e. between one system and an isolated section of the other system).

APPENDIX C

C1. Remaining Hydroelectric Potential in Canada*

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
NEWFOUNDLAND				
Gull Island	1 698	1 698	1 698	76
Muskrat Falls	618	618	618	87
Lobstick	160	160	160	71
Pinware	77	77	77	67
Alexis	98	98	98	72
Paradise (Lab.)	89	89	89	66
Minipi	255	255	255	76
Fig	204	204	204	77
Eagle River	661	661	661	71
Naskaupi	290	290	290	73
Kaniriktok	394	394	394	75
Granite Canal	31	31	31	80
Island Pond	30	30	30	70
Round Pond	18	18	18	84
Sub total	4 623	4 623	4 623	
OTHER SITES				
> 10 MW	186	-	-	61
< 10 MW	392	-	-	61
TOTAL ALL SITES	5 201	4 623	4 623	
NOVA SCOTIA				
> 10 MW	75	75	-	61
< 10 MW	15	15	-	61
Sub total	90	90	-	
TIDAL				
Cumberland Basin	1 428	1 428	-	26
Minas Basin	5 338	5 338	-	30
Shepody Bay	1 643	1 643	-	25
TOTAL ALL SITES	8 499	8 499	0	
NEW BRUNSWICK				
Grand Falls (Ext)	300	300	300	21
Morrill	140	140	140	35
OTHER SITES	340	-	-	61
TOTAL ALL SITES	780	440	440	

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
QUEBEC				
LG-1	1 296	1 296	1 296	64
Laforge-1	783	783	783	61
Brisay	385	385	385	68
Eastmain-1	522	522	522	63
Eastmain-2	200	200	-	74
Ste-Marguerite	822	822	822	58
Grande Baleine	2 891	2 891	2 891	60
Ashuapmushuan	533	533	533	77
NBR	8 700	8 700	8 700	61
Nastapoca	768	768	-	59
Sakami	187	187	-	79
La Romaine	1 710	1 710	1 710	59
Laforge-2	270	270	270	72
Haut St-Maurice	499	499	-	64
Matawin	212	212	-	75
Outaouais Sup.	281	281	-	45
Rapide-Manigance	78	78	-	88
Temiscamingue	195	195	-	53
Toulnoustouc	71	71	-	48
Aguanus	329	329	-	79
Magpie	354	354	-	79
Moisie	1 014	1 014	-	79
Musquaro	86	86	-	78
Natashquan	703	703	-	79
Olomane	300	300	-	80
Petit-Mecatina	1 754	1 754	-	59
St-Augustin	66	66	-	59
St-Paul	157	157	-	53
A-la-Baleine	807	807	-	78
Arnaud-Payne	592	592	-	67
Aux-Feuilles	711	711	-	80
Caniapiscau	2 240	2 240	-	81
Eau-Claire	321	321	-	60
George	2 826	2 826	-	80
Harricana	1 032	1 032	-	80
Archipel	418	418	-	93
Other Ident. Sites	5 200	5 200	-	61
OTHER SITES	4 800	-	-	61
Sub total	44 113	39 313	17 912	
TIDAL	26 416	-	-	25
TOTAL ALL SITES	70 529	39 313	17 912	

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
ONTARIO				
Long Sault Rapids	52	52	52	52
Abitibi Canyon (Ext)	464	464	464	3
Newpost Creek	26	26	-	77
Otter Rapids (Ext)	174	174	174	3
Nine Mile Rapids	295	295	295	28
Sand Rapids	131	131	-	31
Allan Rapids	131	131	-	31
Ear Falls (Ext)	15	15	15	37
Maynard Falls	47	47	47	57
Little Jackfish	132	132	132	49
Highland Falls	94	94	-	18
Farm Rapids	13	13	-	52
Steephill Falls	15	15	-	50
Magpie Falls	13	13	-	50
Mission Falls	15	15	-	51
Yellow Falls	54	54	-	26
Cypress Falls	42	42	-	29
Little Long (Ext)	61	61	61	13
Smoky Falls (Redev)	182	182	182	30
Harmon	68	68	68	16
Kipling	68	68	68	16
Grand Rapids	174	174	174	41
Thunderhouse Falls	42	42	-	48
Long Rapids	126	126	-	44
Mileage 66	81	81	-	40
Mileage 25	80	80	-	40
Patten Post	250	250	250	17
Ragged Chute (Redev)	89	89	89	20
Grey Goose	140	140	140	48
Renison	135	135	135	47
Adam Beck	565	565	565	35
Paquette Rapids	29	29	-	89
Mileage 74	58	58	-	17
Mileage 9	65	65	-	18
Spanish Site 4	80	80	-	38
Spanish Site 1	40	40	-	38
Denison Falls	36	36	-	29
Chicagouse Falls	28	28	-	38
Turnbull	20	20	-	38
Umbata Falls	51	51	-	40
Chigamiwingum	57	57	-	41
Sub total	4 238	4 238	2 911	
OTHER SITES				
> 10 MW	6 784	-	-	43
< 10 MW	1 365	-	-	67
TOTAL ALL SITES	12 387	4 238	2 911	

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
MANITOBA				
Conawapa	1 240	1 240	1 240	64
Gillam Island	1 000	1 000	1 000	65
Gull	550	550	550	62
Birthday	550	550	550	68
Red Rock	220	220	220	67
Whitemud	280	280	280	61
Granville Falls	150	150	150	61
First Rapids	190	190	190	84
Manasan	260	260	260	70
Wuskwatim	330	330	330	69
Notigi	100	100	100	68
Kelsey (Ext)	220	220	220	26
Sub total	5 090	5 090	5 090	
OTHER SITES				
> 10 MW	3 000	-	-	61
< 10 MW	100	-	-	61
TOTAL ALL SITES	8 190	5 090	5 090	
SASKATCHEWAN				
Island Falls (Ext)	100	100	100	25
Wintego	285	285	285	68
Choiceland	150	150	150	48
Forks	400	400	400	51
Sub total	935	935	935	
OTHER SITES	1 254	-	-	61
TOTAL ALL SITES	2 189	935	935	

Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
ALBERTA				
Berland	71	71	-	61
McLeod	36	36	-	61
McLeod Valley	22	22	-	61
Pembina	12	12	-	61
Cardinal	3	3	-	61
Elk	25	25	-	61
Frontal	19	19	-	61
Isaak	18	18	-	61
Job	4	4	-	61
Olympus	11	11	-	61
Race	8	8	-	61
Southesk Diversion	21	21	-	61
Strike	27	27	-	61
Thistle	25	25	-	61
Thunder	19	19	-	61
Horseguard	1	1	-	61
Brazeau Forks	88	88	-	61
Carvel	135	135	-	61
Chambers Creek	47	47	-	61
Drayton Valley	162	162	-	61
Gap	91	91	-	61
Hairy Hill	182	182	-	61
Phoenix	80	80	-	61
Ramparts	122	122	-	61
Rocky Mountain	49	49	-	61
Shunda	48	48	-	61
Whirlpool	10	10	-	61
Magnolia	7	7	-	61
Vermillion	12	12	-	61
Carcajou	1 329	1 329	-	61
Dunvegan	256	256	256	61
Mile 232	898	898	-	61
Mile 251	1 011	1 011	-	61
Vermillion Chutes	75	75	-	61
18th Baseline	210	210	-	61
19th Baseline	337	337	-	61
Bolton	124	124	-	61
Cutbank	174	174	-	61
Kakwa	346	346	-	61
Meander	292	292	-	61
Peace River	253	253	-	61
Sulphur	84	84	-	61
Wapiti	228	228	-	61
Watino	346	346	-	61
West Watino	318	318	-	61
Dickson	7	7	-	61
Raven Dam Site	7	7	-	61
Alternative 4	1 667	1 667	1 667	61

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
Bassano	1	1	-	61
Cochrane	19	19	-	61
Dalemead	112	112	-	61
Eyremore	17	17	-	61
Glenbow	29	29	-	61
Lac des Arcs	15	15	-	61
Radnor	21	21	-	61
Russell	41	41	-	61
Shepard	78	78	-	61
Castle Site (1978)	7	7	-	61
Brocket	14	14	-	61
Fort MacLeod	7	7	-	61
Three Rivers	25	25	-	61
Meridan	45	45	-	61
Rapid Narrows	14	14	-	61
Sub total	9 762	9 762	1 923	
OTHER SITES	9 051	-	-	61
TOTAL ALL SITES	18 813	9 762	1 923	

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
BRITISH COLUMBIA				
Peace Site C	900	900	900	61
Keenleyside	180	180	180	54
Murphy Creek	275	275	275	74
Stikine-Iskut	2 900	2 900	2 900	61
Liard River	3 190	3 190	3 190	66
Falls River	22	22	22	47
Seven Mile Unit 4	200	200	200	16
Homathko	900	900	710	55
Elaho	340	340	340	70
Border	250	250	250	74
McGregor	360	360	360	61
Kemano Completion	520	520	520	61
Waneta (Ext)	190	190	190	30
Brilliant (Ext)	120	120	120	50
Shuswap	55	55	55	80
Beatrice Lake	31	31	31	68
Goat River	12	12	12	26
Peace Site E	600	600	-	61
Skeena	1 080	1 080	-	61
Yukon-Taku	3 700	3 700	-	61
Thorsen Creek	3	3	-	61
OTHER SITES	14 969	-	-	61
Sub total	30 797	15 828	10 255	
TIDAL				
Observation Inlet	662	662	-	25
Sechelt Inlet	54	54	-	25
TOTAL ALL SITES	31 513	16 544	10 255	

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
YUKON				
Mid Yukon	560	560	560	68
Cassiar Bar	350	350	350	68
Wolverine	476	476	476	68
Detour	100	100	100	68
Granite	414	414	414	68
High Fraser Falls	300	300	300	68
Porcupine/Steward	110	110	83	68
False Canyon/Francis River	58	58	58	68
Lower Canyon	75	75	75	68
Liard Canyon	90	90	90	68
Aberdeen Falls/Pee	300	300	300	68
Bell/Porcupine River	110	110	110	68
Slate Rapids	42	42	42	68
Hoole Canyon	40	40	40	68
Hoole River	15	15	15	68
Ross River	30	30	30	68
Primrose/Kusawa	30	30	30	68
Little Salmon	15	15	15	68
Yukon-Taku	2 500	2 500	-	68
Yukon-Yaiga	3 000	3 000	-	68
Pelly River	630	630	-	68
Steward River	973	973	-	68
Frances River	150	150	-	68
Tashenshini River	160	160	-	68
Bates River	110	110	-	68
Peel River	300	300	-	68
Sub total	10 938	10 938	3 088	
OTHER SITES	761	-	-	68
TOTAL ALL SITES	11 699	10 938	3 088	

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
N.W.T.				
Anderson	160	160	-	60
Back	2073	2073	1162	60
Burnside	525	525	-	60
Camsell	29	29	-	60
Coppermine	279	279	149	60
Dubawnt River	178	178	-	60
Ferguson	16	16	-	60
Great Bear 1	438	438	204	60
Great Bear 2	414	414	-	60
Hornaday	91	91	-	60
Horton	115	115	-	60
Hayes	120	120	-	60
Hood	52	52	-	60
Kakisa	21	21	13	60
Kasan	64	64	-	60
Maguse	39	39	-	60
Nahanni/Virginia	232	232	216	60
Nahanni	339	339	-	60
Flat	18	18	-	60
Lockhart	387	387	126	60
Pikes Portage	148	148	126	60
Quoich	207	207	-	60
Tha-Anne	41	41	-	60
Taltson	113	113	34	60
Tazzin	15	15	-	60
Thelon	188	188	34	60
Thlewiaza	73	73	-	60
Trout	10	10	6	60
Slave	1130	1130	370	60
Sylvia Grinnell	86	86	6	60
Snowdrift	6	6	-	60
Arctic Red	80	80	-	60
Peel	200	200	-	60
Rat	450	450	-	60
Keele	70	70	-	60
Mountain	70	70	-	60
Root	55	55	-	60
Redstone	135	135	-	60
Dahadinni	160	160	-	60
Willow Lake	20	20	-	60

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Remaining Hydroelectric Potential in Canada* (Continued)

Sites	Gross Potential (MW)	Identified Potential (MW)	Planning Potential (MW)	Capacity** Factor (%)
Lamartre	27	27	-	60
Armshow	20	20	-	60
Anna Maria Port	7	7	-	60
Ward Inlet	15	15	-	60
Petitot	27	27	-	60
Hanbury	246	246	-	60
Prince	4	4	-	60
Maguse	3	3	-	60
Sub total	9 196	9 196	2 446	
OTHER SITES	28	-	-	60
TOTAL ALL SITES	9 224	9 196	2 446	
CANADA TOTAL	179 024	109 578	49 623	

* *Estimated.*

** *Capacity factors have been rounded off. In some cases, capacity factors have been estimated using 61 per cent for hydro and 25 per cent for tidal.*

Ext *Extension.*

Redev *Redevelopment.*

Source: *Canadian electric utilities and Energy, Mines and Resources Canada.*

Definitions and Abbreviations

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kW.h).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kW.h). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt-hour (GW.h): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP): The total value of production of goods and services measured at market prices.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h): A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Terawatt Hours (TW.h): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

ELECTRIC POWER IN CANADA 1988

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Energy Sector
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1. THE ELECTRIC POWER INDUSTRY IN CANADA

INDUSTRY STRUCTURE

Under the Canadian Constitution, electricity is primarily within the jurisdiction of the provinces. As a consequence, Canada's electrical industry is organized along provincial lines. In most provinces, the industry is highly integrated, with the bulk of the generation, transmission, and distribution provided by a few dominant utilities. Although some of these utilities are privately owned, most are Crown corporations owned by the provinces. The dominant utilities are listed in Table 1.1.

Among the major electric utilities, eight are provincially owned, four are investor owned, two are municipally owned, and two are territorial Crown corporations. In 1988, provincial electric utilities owned about 85.1 per cent of total installed generating capacity and produced about 82.5 per cent of total generated electricity. The four investor-owned utilities accounted for 5.8 per cent of all Canadian electric utility capacity and produced about 7.4 per cent of total electricity. Municipally owned utilities accounted for 1.2 per cent of capacity ownership, and produced 0.5 per cent of total generated electricity; two territorial Crown corporations accounted for 0.3 per cent and 0.2 per cent of capacity and generation respectively.

In addition to the 16 major electric utilities, there are about 60 industrial establishments generating electricity mainly for their own use. A few also sell energy to municipal distribution systems or utilities. These

Table 1.1. Canada's major electric utilities by province

Province	Utility	Ownership
Newfoundland	Newfoundland and Labrador Hydro	Provincial
	Newfoundland Light & Power Co. Ltd.	Private
Prince Edward Island	Maritime Electric Co. Ltd.	Private
Nova Scotia	Nova Scotia Power Corporation	Provincial
New Brunswick	New Brunswick Electric Power Commission	Provincial
Quebec	Hydro-Québec	Provincial
Ontario	Ontario Hydro	Provincial
Manitoba	The Manitoba Hydro-Electric Board	Provincial
	City of Winnipeg Hydro-Electric System	Municipal
Saskatchewan	Saskatchewan Power Corporation	Provincial
Alberta	Alberta Power Ltd.	Private
	Edmonton Power	Municipal
	TransAlta Utilities Corporation	Private
British Columbia	British Columbia Hydro and Power Authority	Provincial
Yukon	Yukon Energy Corporation	Territorial
Northwest Territories	Northwest Territories Power Corporation	Territorial

Source: Energy, Mines and Resources Canada.

industries are concentrated in the pulp and paper, mining, and aluminum smelting sectors. In 1988, industrial establishments owned about 6.1 per cent of total capacity and produced about 7.8 per cent of total generated electricity in Canada, as shown in Table 1.2.

In addition to the major electric utilities and industrial establishments, there are about 364 smaller utilities across Canada, 87 per cent of which are located in Ontario. Most of these small utilities are owned by municipalities. They do not own generating capacity; instead, they usually purchase power from the major utility in their province. Several small investor-owned utilities, however, have their own generating capacity. In 1988, the small utilities accounted for 1.5 per cent of total Canadian capacity and produced 1.6 per cent of electrical energy.

ELECTRICITY AND THE ECONOMY

The electric power industry is a significant presence within the Canadian economy. As indicated in Table 1.3, there were almost 93 000 people directly employed by the industry in 1987, about 0.9 per cent of total Canadian employment. Total revenue increased to about $18.6 billion in 1987 from $17.4 billion in 1986, an increase of 6.9 per cent. Of this total, approximately $0.9 billion or 4.8 per cent came from export earnings. The electric power industry has steadily increased its contribution to Canada's Gross Domestic Product, from 2.3 per cent in 1960, to 2.5 per cent in 1970, to 3.0 per cent in 1980, and 3.2 per cent in 1987.

Total assets of the industry were about $98.7 billion in 1987, accounting for about 7 per cent of the capital stock of the economy. This reflects the capital-intensive nature of the electric power industry. Ontario Hydro, Hydro-Québec, and B.C. Hydro were the three largest electric utilities in Canada and, in terms of assets, ranked first, second, and sixth respectively among all Canadian companies.

Table 1.2. Electrical capacity and production by utilities and industrial establishments, 1930-1988

	Installed Generating Capacity		Energy Production	
Year	Utilities	Industrial Establishments	Utilities	Industrial Establishments
	(per cent)			
1930	83	17	93	7
1940	84	16	91	9
1950	83	17	88	12
1960	80	20	78	22
1965	82	18	77	23
1970	88	12	84	16
1975	90	10	87	13
1980	92	8	89	11
1981	92	8	90	10
1982	93	7	90	10
1983	93	7	90	10
1984	93	7	91	9
1985	93	7	92	8
1986	94	6	92	8
1987	94	6	91	9
1988	94	6	92	8

Source: ***Electric Power Statistics, Volume II****, Statistics Canada, 57-202, 57-001.*

CANADIAN ELECTRIC UTILITIES

Newfoundland

In Newfoundland, the generation and distribution of electricity is dominated by two utilities, Newfoundland Light & Power Company Limited (NLPC) and Newfoundland and Labrador Hydro (NLH). Together, NLPC and NLH serve about 200 000 customers.

NLPC, an investor-owned utility, is the primary retailer of electricity on the island. NLPC was incorporated in 1966 through the amalgamation of St. John's Electric Light Company Limited, United Towns Electric Company Limited, and Union Electric Light and Power Company.

Approximately 89 per cent of the company's power supply is purchased from NLH, with the balance generated by its own hydro stations.

NLH is a provincial Crown corporation, whose mandate is to generate and transmit electricity in the province. It was established by an act of the provincial legislature in 1954 and was incorporated in 1975. It is the parent company of a group that includes Churchill Falls (Labrador) Corporation (CFLCo), the Lower Churchill Development Corporation

Table 1.3. Electric utility assets, revenue and employees, 1987

Utility	Assets	Revenue	Employees
	($ millions)		(persons)
Major utilities			
Newfoundland and Labrador Hydro	2 147	332	1 355
Newfoundland Light & Power Co. Ltd.	390	251	914
Maritime Electric Co. Ltd.	93	61	202
Nova Scotia Power Corporation	1 509	510	2 420
NB Electric Power Commission	2 846	867	2 410
Hydro-Québec	31 659	5 095	22 264
Ontario Hydro	32 657	5 280	32 147
The Manitoba Hydro-Electric Board	3 832	580	4 222
City of Winnipeg Hydro-Electric System	123	92	648
Saskatchewan Power Corporation*	2 939	859	2 881
TransAlta Utilities	3 684	925	2 515
Edmonton Power	1 129	280	913
Alberta Power Ltd.	1 414	409	1 393
B.C. Hydro and Power Authority*	9 561	2 110	6 419
Yukon Energy Corporation	95	26	86
Northern Canada Power Commission	138	76	354
Other utilities	4 465	865	11 644
Canada	98 681	18 618	92 787

* *Includes natural gas operations*

Source: Electric utilities' annual reports

(LCDC), Twin Falls Power Corporation Limited, Gull Island Power Co. Ltd., and the Power Distribution District of Newfoundland and Labrador. NLH has 51 per cent ownership in LCDC; the Government of Canada owns the remaining 49 per cent. Through CFLCo, NLH owns and operates the Churchill Falls plant, one of the largest power facilities in the world. NLH's on-island capacity is generated from oil and hydro sources.

Prince Edward Island

Maritime Electric Company Limited (MECL) is an investor-owned utility that has provided electricity service to Prince Edward Island since 1918. The company owns and operates a fully integrated electric utility system providing for the generation, transmission, and distribution of electricity throughout the island. MECL operates two oil-fired generating plants on the island, and it has a 10 per cent equity interest in New Brunswick Electric Power Commission's coal/oil-fired No. 2 unit located in Dalhousie, N.B. It leases from the P.E.I. government the submarine cable interconnection that connects the island to New Brunswick. MECL is the major distributor on the island, serving about 48 600 customers. A municipal utility in the town of Summerside has its own distribution system and purchases power from MECL.

Nova Scotia

The Nova Scotia Power Corporation (NSPC) was incorporated in 1973. It is a provincial Crown corporation that produces and distributes electricity throughout the province. NSPC generates most of its electricity from thermal energy, with more than half of the production coming from coal. The utility also maintains hydro-generation and oil-fired facilities, and purchases power from New Brunswick. The largest portion of the province's total production is derived from the Lingan generating station located on Cape Breton Island. In 1988, NSPC served about 350 000 customers.

New Brunswick

The New Brunswick Electric Power Commission (NB Power) was established by an act of the New Brunswick Legislature in 1920. The mandate of NB Power is to generate and distribute power under public ownership to all areas of the province. The utility owns and operates 14 generating stations, and electricity is generated from a balance of nuclear, hydro, and thermal sources. NB Power also purchases energy from Quebec. In 1988, NB Power directly provided electricity to 253 000 customers and indirectly served an additional 39 000 customers through sales to two municipal utilities.

Quebec

Hydro-Québec is a Crown corporation, established by the provincial Legislative Assembly in 1944. It is responsible for the generation, transmission, and distribution of most of the electricity sold in Quebec. Almost all of the electricity generated by Hydro-Québec at its stations throughout the province is from hydraulic sources. The utility currently serves more than 3.0 million customers.

Hydro-Québec has five wholly owned subsidiaries: the Société d'énergie de la Baie James, which carried out the construction of Phase 1 of La Grande complex and which now manages large construction projects for Hydro-Québec; Hydro-Québec International, which provides engineering and consulting services abroad for electric power projects; Cedars Rapids Transmission Company Limited, which owns and operates a transmission line between Quebec and New York State; Somarex Inc., which was created to finance, construct, and operate a transmission line in the State of Maine; and Nouveler Inc., which promotes energy efficiency and alternative energy sources. Hydro-Québec is also a shareholder in Churchill Falls (Labrador) Corporation Limited, which operates the Churchill Falls power plant.

Ontario

Ontario Hydro is a provincially owned corporation, established in 1906 by the provincial legislature. It has broad powers to produce, buy, and deliver electric power throughout the province and currently operates under the Power Corporation Act. The main responsibility of Ontario Hydro is to provide power to the province's 316 municipal utilities, which in turn distribute power to their own customers. In 1988, more than 3.3 million customers were served by Ontario Hydro and the municipal utilities in the province. In addition, Ontario Hydro supplies about 100 major industrial users directly and over 800 000 rural retail customers in areas or communities not served by municipal utilities. Electricity generated by Ontario Hydro is from a balance of thermal, nuclear, and hydro sources.

In Ontario, there are also a number of small regional utilities. An example is Great Lakes Power Limited, a private hydroelectric generation and distribution utility operating in Sault Ste. Marie and the surrounding area. Great Lakes Power operates nine generating stations primarily located on two river systems flowing into the eastern end of Lake Superior, and is now developing additional capacity on the Magpie River. In 1988, the utility served almost 10 000 customers in northern Ontario directly, and another 30 000 indirectly.

Manitoba

The Manitoba Hydro-Electric Board (Manitoba Hydro) is a Crown corporation established in 1949 by the provincial legislature. It has broad powers to provide electric power throughout the province and operates under the 1970 Manitoba Hydro Act. Almost all of the province's electric power is produced by Manitoba Hydro at its generating stations on the Churchill/Nelson river system in northern Manitoba. Manitoba Hydro distributes electricity to consumers throughout the province, except for the central portion of Winnipeg, which is served by the municipally owned Winnipeg Hydro. Manitoba Hydro and Winnipeg Hydro operate as an integrated electrical generation and transmission system. In 1988, Manitoba Hydro served over 360 000 customers directly, and Winnipeg Hydro served about 113 000 customers.

Saskatchewan

The Saskatchewan Power Corporation (SaskPower) is a Crown corporation operating under the 1950 Power Corporation Act. Under the Act, the mandate of SaskPower includes the generation, transmission, and distribution of electricity and natural gas. At the end of 1988, the corporation served more than 400 000 customers with electricity. The bulk of the electricity generated by SaskPower is from thermal sources.

In 1988, the gas operations of the corporation became separate companies within SaskPower. The parent company of the gas operations is the Saskatchewan Energy Corporation (SaskEnergy). Its subsidiaries are TransGas Limited and Provincial Gas Ltd. In 1988, SaskEnergy served more than 280 000 customers with natural gas.

Alberta

There are three major electric utilities in Alberta: TransAlta Utilities Corporation, Alberta Power Limited, and Edmonton Power. Together, they supply about 91 per cent of Alberta's electrical energy requirements. All are linked by a transmission network largely owned by TransAlta. The remaining 9 per cent of Alberta's electrical energy is supplied by industry. Almost 92 per cent of the electricity generated by Alberta utilities is produced by large coal-fired generating stations.

TransAlta Utilities Corporation, formerly Calgary Power Limited, is the largest investor-owned electric utility in Canada. The company was incorporated under the laws of Canada and has been engaged in the production and distribution of electricity in the Province of Alberta since 1911. About 71 per cent of the electric energy requirements of Alberta are supplied by the company, to over half of the population. In 1988, about 290 000 customers were served directly by TransAlta, while another 300 000 customers were served indirectly through wholesale contracts. TransAlta Utilities has four subsidiaries: TransAlta Resources Corporation; TransAlta Fly Ash Ltd.; Kanelk Transmission Co. Ltd.; and Farm Electric Services Ltd.

Alberta Power Limited, incorporated in 1972, is another investor-owned electric utility in

Alberta, and a subsidiary of Canadian Utilities Limited. The activity of the company is concentrated in east-central and northern Alberta. Alberta Power supplied about 19 per cent of the province's total electricity requirements in 1988, serving about 150 000 customers.

Edmonton Power has the largest generating capacity of any municipally owned utility in Canada. Since its creation in 1902, Edmonton Power has kept pace with the growth and development of Edmonton. Although the utility produced only 1.4 per cent of the electricity requirements of Alberta, it had a 15 per cent share of the total provincial market in 1988, serving more than 235 000 customers. Edmonton Power purchases most of its electricity from TransAlta Utilities and Alberta Power.

British Columbia

British Columbia Hydro & Power Authority (B.C. Hydro), incorporated in 1962, is a Crown corporation operating in British Columbia. B.C. Hydro provides electrical service throughout the province, with the exception of the southern interior, which is served by West Kootenay Power and Light Company, Limited. B.C. Hydro is the third largest electric utility in Canada. B.C. Hydro generates, transmits, and distributes electricity to more than 1.2 million customers in a service area that contains more than 90 per cent of the population of the province.

In 1988, B.C. Hydro proceeded with a corporate restructuring that resulted in the privatization of its mainland gas operations and its rail operations. The utility also created a number of subsidiaries. The British Columbia Power Export Corporation (Powerex) will act as a provincial electricity export agency. The utility's former research and development division is now the wholly owned subsidiary Powertech Laboratories Inc. The computer and management systems division has been reorganized into two subsidiaries: Westech Information Systems Inc. and Western Integrated Technologies Inc.

West Kootenay Power is an investor-owned utility supplying electric service in the southern interior of British Columbia. The company generates and distributes hydroelectricity directly to more than 60 000 customers in its service area. The company also supplies power to seven wholesale customers, who in turn serve almost 38 000 customers. West Kootenay Power is owned by UtiliCorp United Inc. of Missouri.

Yukon

Two utilities provide electrical service in the Yukon. The largest of these, in terms of revenues and generating capacity, is the Yukon Energy Corporation. It is a territorial Crown corporation that has taken over responsibility for the Yukon assets of the Northern Canada Power Commission (NCPC). The Yukon Development Corporation (the parent corporation of the Yukon Energy Corporation) has entered into a five-year management services agreement with the Yukon Electrical Company Limited (YECL). Under the terms of the agreement, YECL will operate the Yukon Energy Corporation's assets, purchase the electricity generated, and distribute it to the Energy Corporation's customers. The Energy Corporation's customers include all of the Yukon's major industries and 13 per cent of the Yukon's non-industrial customers.

In addition to its responsibilities to the Yukon Energy Corporation, YECL (a subsidiary of Canadian Utilities Limited) also generates and distributes power to its own customers. YECL serves 18 communities in the Yukon, including Whitehorse. It purchases the majority of its electrical requirements from the Yukon Energy Corporation.

Northwest Territories

Electrical service in the Northwest Territories is provided by the Northwest Territories Power Corporation (NWTPC) and Northland Utilities Enterprises Limited (Northland). The largest of these, in terms of revenues and generating capacity, is the NWTPC. It is a territorial Crown corporation, which in 1988 took over responsibility for the Northwest Territories' assets of the Northern Canada Power Commission. NWTPC provides electrical service to 51 communities in the N.W.T. and wholesales hydro-power to Northland.

Northland is an investor-owned utility and is a subsidiary of Canadian Utilities Limited. It provides electrical service to seven communities in the south-western region of the N.W.T.

2. CANADIAN ELECTRICITY IN THE INTERNATIONAL CONTEXT

Canada has a significant place in the world electric power industry. Canada is not only a world leader in long-distance electric power transmission, but also an important producer and consumer.

In 1986, Canada ranked fourth in the world both in installed generating capacity and electricity generation, next to the United States, U.S.S.R., and Japan (tables 2.1 and 2.2). Canada's total installed capacity accounted for 4 per cent of the world total, while its production accounted for 5 per cent. In addition, Canada was the largest hydroelectric energy producer in the world in 1986 (311 TW.h.), accounting for about 15 per cent of total world hydro production (Table 2.2).

Canada's per capita electricity consumption ranked second in the world in 1986, next only to Norway (Table 2.3). Canada was one of the few developed countries with a high electricity consumption growth rate during the period 1984-86 (Table 2.4). In general, most of the countries with high consumption growth rates were developing countries. This was largely due to the fact that many of these countries have been engaged in the industrialization of their economies and, as a result, have increased their electrical energy consumption significantly.

Table 2.1. International comparison of installed generating capacity, 1986*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
			(MW)		
United States	547 111	84 152	86 548	1 633	719 444
U.S.S.R.	229 420	62 141	30 110	0	321 671
Japan	111 800	35 150	26 165	214	173 329
Canada	30 600	56 800	11 000	0	98 400
France	24 600	22 800	44 700	0	92 100
China	60 000	27 000	0	0	87 000
West Germany	57 076	6 710	18 874	3	82 660
United Kingdom	55 177	4 190	7 144	1	66 512
Italy	36 617	17 863	1 273	452	56 205
India	37 494	15 965	1 230	0	54 689
Brazil	6 390	37 702	657	0	44 749
Spain	15 102	14 431	5 546	0	35 079
Australia	26 199	7 029	0	250	33 478
Sweden	7 634	15 813	9 648	5	33 100
Poland	27 797	1 976	0	0	29 773
South Africa	23 190	572	965	0	24 727
Mexico	17 059	6 601	0	425	24 085
Norway	254	23 418	0	0	23 672
East Germany	18 385	1 844	1 830	0	22 059
Czechoslovakia	14 614	2 897	2 860	0	20 371
World Total **	1 614 128 (65.6%)	566 823 (23.0%)	274 504 (11.2%)	4 981 (0.2%)	2 460 436 (100%)

* *Includes the 20 countries with the largest electrical systems.*
** *Total for all 188 countries or areas listed in source reference.*

Source: ***Energy Statistics Yearbook, 1986****, United Nations, pp.322-348.*

Canada continued to be the largest electricity exporter in 1986, accounting for 18 per cent of the total world electricity trade (Table 2.5).

In 1986, Canada surpassed Norway as the most electricity-intensive economy of all 24 OECD-member countries (Table 2.7). Tables 2.8, 2.9 and 2.10 indicate that Canada's electricity prices are highly competitive in the residential, commercial, and industrial sectors relative to other countries. Japan's high electricity prices are due in part to a substantial appreciation in the value of the yen.

Table 2.2. International comparison of electricity generation by fuel type, 1986*

Country	Conventional Thermal	Hydro	Nuclear	Geothermal	Total
			(GW.h)		
United States	1 861 601	294 594	414 038	12 277	2 582 510
U.S.S.R.	1 222 348	215 738	160 804	0	1 598 890
Japan	415 350	86 560	168 310	1 550	671 770
Canada	86 602	310 702	71 267	0	468 571
China	344 130	100 000	0	0	444 130
West Germany	270 141	16 664	119 580	0	406 386
France	40 786	60 859	241 400	0	343 045
United Kingdom	235 009	4 067	59 079	1	298 156
Brazil	18 859	182 615	144	0	201 618
India	143 788	53 764	5 022	0	202 574
Italy	136 281	41 190	8 758	2 760	188 989
Poland	136 512	3 782	0	0	140 294
Sweden	7 080	60 694	70 243	6	138 023
Spain	63 953	26 314	37 446	0	127 713
South Africa	117 662	733	3 925	0	122 320
Australia	111 307	15 515	0	837	127 659
East Germany	102 616	1 767	10 908	0	115 291
Norway	432	95 927	0	0	96 359
Mexico	68 330	27 437	0	1 715	97 518
Czechoslovakia	62 919	3 991	17 865	0	84 775
World Total**	6 344 241	2 027 100	1 556 323	29 600	9 962 264
	(63.7%)	(20.4%)	(15.6%)	(0.3%)	(100%)

* *Includes the world's 20 largest electrical energy producers.*
** *Total for all 188 countries or areas listed in source reference.*

*Source: **Energy Statistics Yearbook, 1986**, United Nations, pp.378-404.*

Table 2.3. International comparison of per capita electricity consumption, 1986*

Country	kW.h/Person	As Percentage of World Average
Norway	23 706	1 169
Canada	16 914	834
Iceland	16 727	824
Sweden	15 979	788
Luxembourg	11 165	551
United States	10 906	538
Finland	10 708	528
Qatar	10 642	525
New Zealand	8 411	415
Australia	8 029	396
East Germany	6 928	342
West Germany	6 774	334
Denmark	6 015	297
France	5 798	286
Belgium	5 791	286
Austria	5 688	280
U.S.S.R.	5 582	275
Japan	5 533	273
United Kingdom	5 366	265
Netherlands	4 774	235
Italy	3 681	182
Spain	3 262	161
South Africa	3 195	158
Argentina	1 578	78
Brazil	1 532	76
Mexico	1 188	59
Egypt	523	26
China	423	21
India	262	13
Nigeria	99	5
World Average **	2 028	100

* *The first ten countries are listed according to their actual global rankings. The remaining countries are given in descending order of consumption; however, since only the most populous countries from each region were selected, the list does not indicate their true global rankings.*

** *Average for all 188 countries or areas included in source reference.*

Source: ***Energy Statistics Yearbook, 1986,*** *United Nations, pp.406-419.*

Table 2.4. International comparison of total electricity consumption growth rates

Country	1984	1985	1986	Average 1984-86
		(per cent)		
Jordan	18.1	9.2	10.1	12.5
Indonesia	9.0	21.2	3.7	11.3
Turkey	12.6	6.5	14.2	11.1
India	12.0	8.6	10.3	10.3
Kuwait	10.7	10.5	9.7	10.3
South Korea	10.0	7.5	11.2	9.6
Pakistan	11.0	5.2	12.0	9.4
Thailand	11.1	9.5	7.2	9.3
Brazil	9.9	7.8	8.5	8.7
China	7.4	9.0	8.2	8.2
Malaysia	8.1	9.6	7.0	8.2
Singapore	8.5	5.3	7.6	7.1
Australia	6.3	7.7	4.9	6.3
France	5.4	7.1	5.1	5.9
Sweden	8.7	9.2	-1.2	5.6
Canada	6.4	5.0	3.8	5.1
Argentina	4.5	0.8	8.3	4.5
U.S.S.R	5.2	3.3	3.6	4.0
Spain	5.1	3.4	1.6	3.4
Italy	4.8	2.7	2.5	3.3
Egypt	3.4	5.7	0.7	3.3
New Zealand	3.9	3.1	3.0	3.3
United Kingdom	1.8	4.8	3.0	3.2
United States	4.8	3.5	0.5	2.9
Japan	4.9	3.6	0.0	2.8
West Germany	3.8	3.1	0.6	2.5
World Total*	5.5	4.3	2.7	4.2

* *Total for all 188 countries or areas included in source reference.*

Source: Calculated from ***Energy Statistics Yearbook, 1986****, United Nations, pp.406-419.*

Table 2.5. International comparison of electricity exports, 1986*

Country	Exports** (GW.h)	Production (GW.h)	Percentage of Exports to Production
Canada	38 934	468 571	8.3
France	33 000	343 045	9.6
U.S.S.R	29 000	1 598 890	1.8
Switzerland	23 098	54 857	42.1
West Germany	15 461	406 386	3.8
Czechoslovakia	8 620	84 775	10.2
Poland	7 796	140 294	5.6
Austria	7 426	44 134	16.8
Sweden	6 451	138 023	4.0
Belgium	5 521	57 621	9.6
United States	4 816	2 582 510	0.2
Spain	4 152	127 713	3.3
East Germany	3 873	115 291	3.4
Uruguay	3 151	7 429	42.4
Zambia	3 100	10 100	30.7
Yugoslavia	2 178	77 381	2.8
Norway	2 169	96 359	2.3
Denmark	2 083	30 720	6.8
Italy	1 814	188 989	1.0
Bulgaria	1 470	41 817	3.5
Mexico	1 468	97 518	1.5
Hungary	1 346	28 063	4.8
Hong Kong	1 208	21 412	5.6
Portugal	989	20 225	4.9
Laos	756	1 050	72.0
Total World Exports ***	214 052	9 962 264	2.2

* *Includes the world's 25 largest electricity exporters.*
** *Includes non-cash exchanges.*
*** *Total for all exporting countries or areas listed in source reference.*

Source: ***Energy Statistics Yearbook, 1986****, United Nations, pp.406-419.*

Table 2.6. International comparison of electricity imports, 1986*

Country	Imports** (GW.h)	Consumption (GW.h)	Percentage of Imports to Consumption
United States	40 713	2 582 510	1.6
Italy	23 928	211 103	11.3
West Germany	20 592	411 517	5.0
Switzerland	14 512	46 271	31.4
Hungary	11 862	38 579	30.8
Brazil	10 568	212 177	5.0
Czechoslovakia	10 077	86 232	11.7
Poland	7 833	140 331	5.6
France	7 800	317 845	2.5
Finland	6 212	52 575	11.8
Austria	5 962	44 134	13.5
Bulgaria	5 427	45 774	11.9
Belgium	5 308	57 621	9.2
Canada	4 957	434 594	1.1
East Germany	4 872	116 290	4.2
Norway	4 212	98 402	4.3
Luxembourg	3 915	4 053	96.6
Romania	3 000	74 580	4.0
Zimbabwe	3 000	5 988	50.1
Portugal	2 874	22 110	13.0
Spain	2 896	126 457	2.3
Yugoslavia	2 664	77 867	3.4
Netherlands	2 383	69 494	3.4
Denmark	2 165	30 802	13.0
Sweden	1 819	133 391	1.4
Total World Imports***	220 913	9 969 125	2.2

* *Includes the world's 25 largest electricity importers.*
** *Includes non-cash exchanges.*
*** *Total for all importing countries or areas listed in source reference.*

Source: ***Energy Statistics Yearbook, 1986**, United Nations, pp.406-419.*

Table 2.7. International comparison of electricity intensity*

Country**	1960	1965	1970	1975	1980	1985	1986
				(kW.h/U.S. $1980)			
Canada	1.07	1.07	1.20	1.23	1.29	1.42	1.39
Norway	1.30	1.55	1.56	1.58	1.45	1.59	1.38
Iceland	0.48	0.44	0.84	0.97	0.98	1.07	1.09
New Zealand	0.51	0.63	0.73	0.87	0.98	1.03	1.06
Sweden	0.52	0.58	0.63	0.70	0.78	1.02	0.97
Finland	0.40	0.53	0.60	0.66	0.77	0.91	0.86
United States	0.60	0.65	0.80	0.88	0.89	0.87	0.82
Portugal	0.39	0.44	0.48	0.57	0.68	0.83	0.81
Luxembourg	0.64	1.06	0.78	0.97	0.87	0.80	0.74
Australia	0.37	0.46	0.51	0.58	0.66	0.74	0.73
Greece	0.19	0.25	0.39	0.50	0.58	0.69	0.68
Ireland	0.28	0.38	0.49	0.50	0.57	0.57	0.57
Spain	0.26	0.29	0.37	0.42	0.51	0.56	0.54
Japan	0.45	0.47	0.53	0.57	0.55	0.53	0.51
Austria	0.42	0.44	0.46	0.47	0.49	0.52	0.51
United Kingdom	0.41	0.50	0.56	0.55	0.53	0.52	0.50
Turkey	0.15	0.20	0.26	0.32	0.43	0.48	0.48
West Germany	0.31	0.35	0.40	0.45	0.46	0.49	0.47
Belgium	0.29	0.32	0.36	0.40	0.43	0.47	0.46
France	0.27	0.29	0.32	0.34	0.40	0.44	0.44
Italy	0.34	0.39	0.42	0.46	0.48	0.51	0.41
Switzerland	0.31	0.31	0.32	0.37	0.38	0.42	0.41
Denmark	0.15	0.21	0.30	0.33	0.39	0.41	0.40
Netherlands	0.21	0.26	0.32	0.36	0.38	0.39	0.38

* *Electricity intensity is defined as total electricity consumption per dollar of Gross Domestic Product.*

** *Due to limited availability of data, table includes only OECD-member countries.*

Source: Real Gross Domestic Product in U.S. dollars was obtained from ***National Accounts, 1960-1987****, Department of Economics and Statistics, OECD, February 1989. Electrical energy data were obtained from* ***Energy Statistics Yearbook****, United Nations, various issues.*

Table 2.8. International comparison of electricity prices in the residential sector, 1988*

City	Country	Residential prices (U.S. cents/kW.h)
Cairo	Egypt	1.90
Winnipeg	Canada	3.85
Ottawa	Canada	4.05
Montreal	Canada	4.08
Calgary	Canada	4.15
Edmonton	Canada	4.28
Vancouver	Canada	4.54
Toronto	Canada	4.81
Regina	Canada	5.07
Fredericton	Canada	5.50
St. John's	Canada	5.74
Halifax	Canada	5.91
Stockholm	Sweden	6.28
Sydney	Australia	7.23
Charlottetown	Canada	7.49
Los Angeles	U.S.A.	7.64
Houston	U.S.A.	7.72
Kansas	U.S.A.	7.82
Chicago	U.S.A.	8.05
Rotterdam	Netherlands	10.24
Sao Paulo	Brazil	10.28
Geneva	Switzerland	10.70
New York	U.S.A.	10.96
Madrid	Spain	11.49
Brussels	Belgium	11.80
Dusseldorf	West Germany	12.64
Rome	Italy	16.42
Tokyo	Japan	22.33

* *Based on typical monthly consumption of 750 kW.h.*

Source: Canadian data were obtained from the Electrical Energy Branch, Energy, Mines and Resources Canada. U.S. data were obtained from ***Typical Electric Bills****, Energy Information Administration, Department of Energy, January 1988. Data for other countries were obtained from a survey undertaken by the Electrical Energy Branch, Energy, Mines and Resources Canada, in January 1989.*

Table 2.9. International comparison of electricity prices in the commercial sector, 1988*

City	Country	Commercial prices (U.S. cents/kW.h)
Winnipeg	Canada	3.97
Ottawa	Canada	4.13
Vancouver	Canada	4.44
Calgary	Canada	4.58
Edmonton	Canada	5.01
Montreal	Canada	5.29
Toronto	Canada	5.67
Houston	U.S.A.	6.15
Fredericton	Canada	6.24
Stockholm	Sweden	6.28
Cairo	Egypt	6.40
Regina	Canada	6.73
Charlottetown	Canada	6.80
St. John's	Canada	6.94
Halifax	Canada	7.04
Kansas	U.S.A.	7.45
Los Angeles	U.S.A.	7.51
Chicago	U.S.A.	7.81
Geneva	Switzerland	7.83
Sao Paulo	Brazil	8.00
Brussels	Belgium	10.50
Rome	Italy	10.97
Madrid	Spain	11.23
Rotterdam	Netherlands	11.36
New York	U.S.A.	11.58
Sydney	Australia	11.82
Tokyo	Japan	18.16
Dusseldorf	West Germany	18.87

* *Based on a typical monthly billing demand of 100 kW and energy consumption of 25 000 kW.h.*

Source: Canadian data were obtained from the Electrical Energy Branch, Energy, Mines and Resources Canada. U.S. data were obtained from ***Typical Electric Bills****, Energy Information Administration, Department of Energy, January 1988. Data for other countries were obtained from a survey undertaken by the Electrical Energy Branch, Energy, Mines and Resources Canada, in January 1989.*

Table 2.10. International comparison of electricity prices in the industrial sector, 1988*

City	Country	Industrial prices (U.S. cents/kW.h)
Cairo	Egypt	1.20
Winnipeg	Canada	2.81
Calgary	Canada	3.30
Vancouver	Canada	3.35
Montreal	Canada	3.60
Ottawa	Canada	3.70
Fredericton	Canada	3.98
Edmonton	Canada	4.02
Toronto	Canada	4.30
Halifax	Canada	4.54
Houston	U.S.A.	5.15
St. John's	Canada	5.18
Stockholm	Sweden	5.27
Regina	Canada	5.35
Kansas	U.S.A.	5.77
Sydney	Australia	5.85
Charlottetown	Canada	5.93
Geneva	Switzerland	5.97
Chicago	U.S.A.	6.01
Los Angeles	U.S.A.	6.68
Sao Paulo	Brazil	6.82
Rome	Italy	7.44
Brussels	Belgium	7.90
Madrid	Spain	8.62
New York	U.S.A.	9.60
Rotterdam	Netherlands	10.24
Dusseldorf	West Germany	10.82
Tokyo	Japan	11.80

* *Based on a typical monthly billing demand of 1 000 kW and energy consumption of 400 000 kW.h.*

Source: *Canadian data were obtained from the Electrical Energy Branch, Energy, Mines and Resources Canada. U.S. data were obtained from* ***Typical Electric Bills,*** *Energy Information Administration, Department of Energy, January 1988. Data for other countries were obtained from a survey undertaken by the Electrical Energy Branch, Energy, Mines and Resources Canada, in January 1989.*

3. ELECTRICITY CONSUMPTION

Electricity consumption is affected by many factors: economic activity, demographic variables, electricity prices, other energy prices, conservation, technological changes, and weather. However, aggregate economic activity (as measured by the Gross Domestic Product) is the most important variable.

Between 1960 and 1988, real Gross Domestic Product grew at 4.4 per cent annually, compared with 5.3 per cent for electricity consumption (tables 3.1 and 3.2). During the same period, the average annual growth rate of petroleum demand was 2.4 per cent, coal 3.6 per cent, and natural gas 7.2 per cent.

Peak demand grew at a slightly faster rate than that of energy demand. From 1960 to 1988, the average annual growth rate for peak demand in Canada was 5.5 per cent, compared with energy demand at 5.3 per cent (Table 3.5). This implies that the load factor for the Canadian electric system has declined since 1960 (Table 3.6).

Figure 3.1. Primary energy consumption in Canada*

Total consumption: 4 045 petajoules | **Total consumption: 10 919 petajoules**

* *Primary energy is the amount of energy available to the final consumer, plus conversion losses and energy used by the energy supply industries themselves.*
** *Converted at 10.5 megajoules per kilowatt hour.*

Figure 3.2. Secondary energy consumption in Canada*

Total consumption: 2 941 petajoules | **Total consumption 6 369 petajoules**

* *Secondary energy is the amount of energy available to, and used by, the consumer in its final form.*
** *Converted at 3.5 megajoules per kilowatt hour.*

Table 3.1. Electricity consumption by province

	Electricity consumption (GW.h)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1987	1988*	1960-74	1975-88	1960-88	1987-88
Nfld.	1 427	2 684	4 770	6 206	8 545	9 658	9 697	10 423	11.5	4.1	7.4	7.5
P.E.I.	79	137	250	421	518	578	647	704	11.9	4.0	8.1	8.8
N.S.	1 733	2 502	3 706	5 697	6 814	7 626	8 326	8 912	8.7	3.5	6.0	7.0
N.B.	1 684	2 905	4 221	6 713	8 838	10 514	12 376	12 646	10.1	5.0	7.5	2.2
Que.	44 002	52 229	69 730	89 932	118 254	144 761	158 196	163 328	5.4	4.7	4.8	3.2
Ont.	37 157	49 276	69 488	89 197	106 509	122 460	132 174	140 677	6.4	3.6	4.9	6.4
Man.	4 021	5 942	8 601	11 890	13 927	15 912	15 862	16 867	7.9	2.7	5.3	6.3
Sask.	2 124	3 449	5 402	7 187	9 827	12 050	12 452	13 455	9.2	4.9	6.8	8.1
Alta.	3 472	5 603	9 880	15 246	23 172	33 295	36 589	39 325	10.7	7.6	9.1	7.5
B.C.	13 413	19 170	25 761	32 689	42 789	49 150	50 934	54 078	6.9	4.0	5.1	6.2
Yukon	89	109	220	352	381	252	432	439	9.3	1.7	5.9	1.6
N.W.T.	100	159	308	425	494	594	467	466	10.2	0.7	5.7	-0.2
Canada	109 304	144 165	202 337	265 955	340 068	406 859	438 152	461 320	6.6	4.3	5.3	5.3

* *Preliminary data.*

Source: Electric Power Statistics, Volume II, Statistics Canada, catalogue 57-202.

Table 3.2. Electricity consumption in Canada by sector

	Electricity consumption (GW.h)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1987	1988*	1960-74	1975-88	1960-88	1987-88
Residential	20 397	29 738	43 431	64 128	92 440	113 983	119 313	123 650	7.9	5.2	6.7	3.6
	(19)	(20)	(21)	(24)	(27)	(28)	(27)	(27)				
Commercial	12 632	23 859	44 068	65 744	75 912	85 320	98 888	100 741	12.4	3.3	7.7	1.9
	(12)	(17)	(22)	(25)	(21)	(21)	(23)	(22)				
Industrial	66 353	79 118	98 450	109 743	142 247	171 803	185 195	204 052	4.3	4.9	4.1	10.2
	(60)	(55)	(49)	(41)	(42)	(42)	(42)	(44)				
Line losses**	9 920	11 450	16 388	26 340	32 469	35 753	34 758	32 877	6.5	1.7	4.4	-5.4
	(9)	(8)	(8)	(10)	(10)	(9)	(8)	(8)				
Total	109 304	144 165	202 337	265 955	340 068	406 859	438 152	461 320	6.6	4.3	5.3	3.9
	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)				

* *Preliminary data.*
** *Losses during transmission and distribution.*
Figures in parentheses are percentage shares.

Source: ***Electric Power Statistics,*** **Volume II**, *Statistics Canada, catalogue 57-202.*

Figure 3.3. Electricity generation, consumption and net transfers,1988, (GW.h)

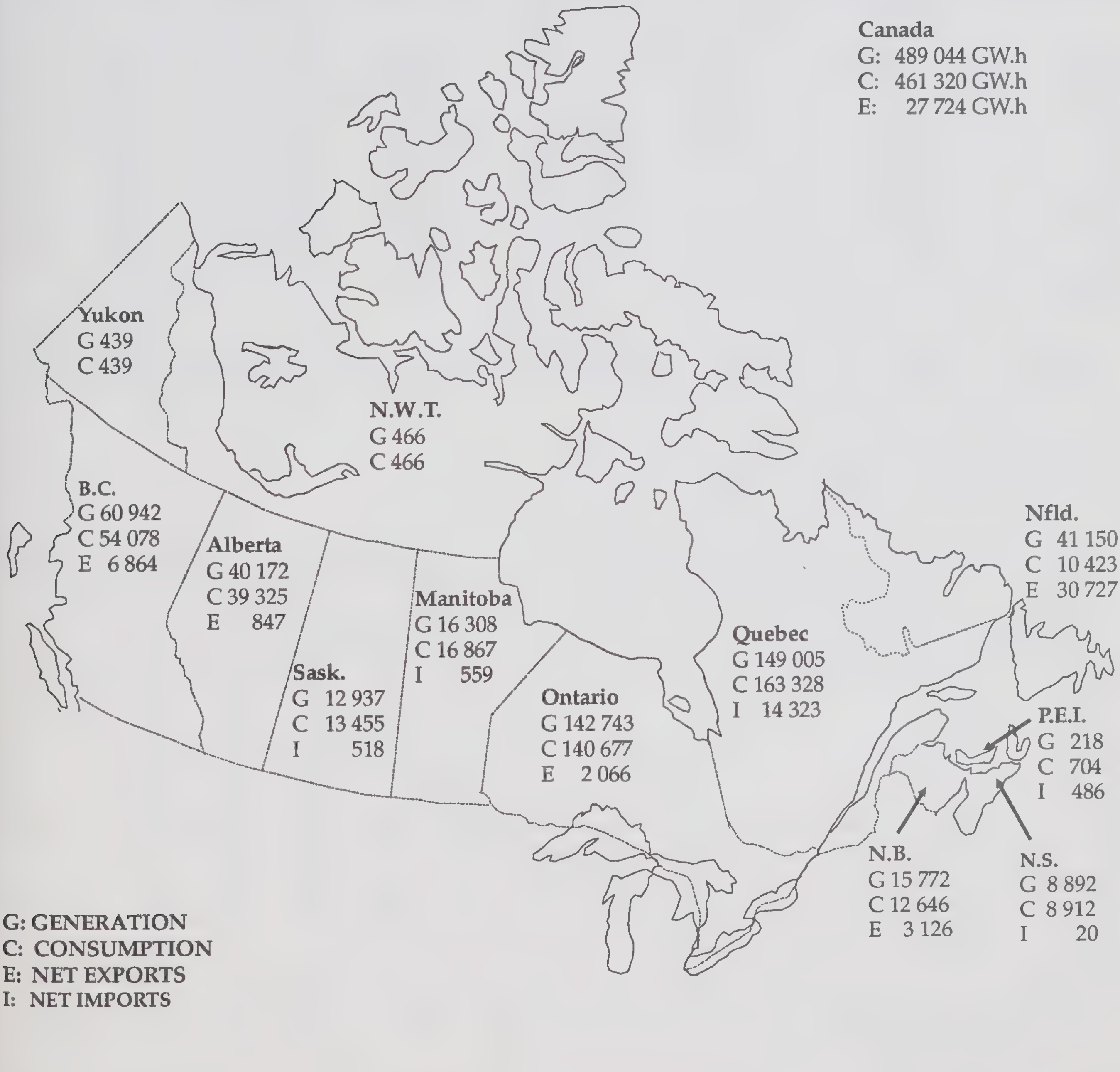


Table 3.3. Provincial electricity consumption and generation, 1988 (GW.h)

	Generation	Exports to Provinces	Exports to U.S.A.*	Imports from Provinces	Imports from U.S.A.*	Consumption
Nfld.	41 150	30 727	0	0	0	10 423
P.E.I.	218	0	0	486	0	704
N.S.	8 892	166	0	186	0	8 912
N.B.	15 772	981	5 191	2 856	190	12 646
Que.	149 005	4 979	11 863	31 079	86	163 328
Ont.	142 743	65	7 439	2 827	2 611	140 677
Man.	16 308	1 908	628	1 126	1 969	16 867
Sask.	12 937	1 109	57	1 369	315	13 455
Alta.	40 172	1 218	0	369	0	39 325
B.C.	60 942	364	8 851	1 219	1 132	54 078
Yukon	439	0	0	0	0	439
N.W.T.	466	0	0	0	0	466
Canada	489 044	41 517	34 029	41 517	6 305	461 320

* *Service exchange is included.*

Source: Energy, Mines and Resources Canada.

Figure 3.4. Historical relationship between electricity demand and GDP, 1960-1988

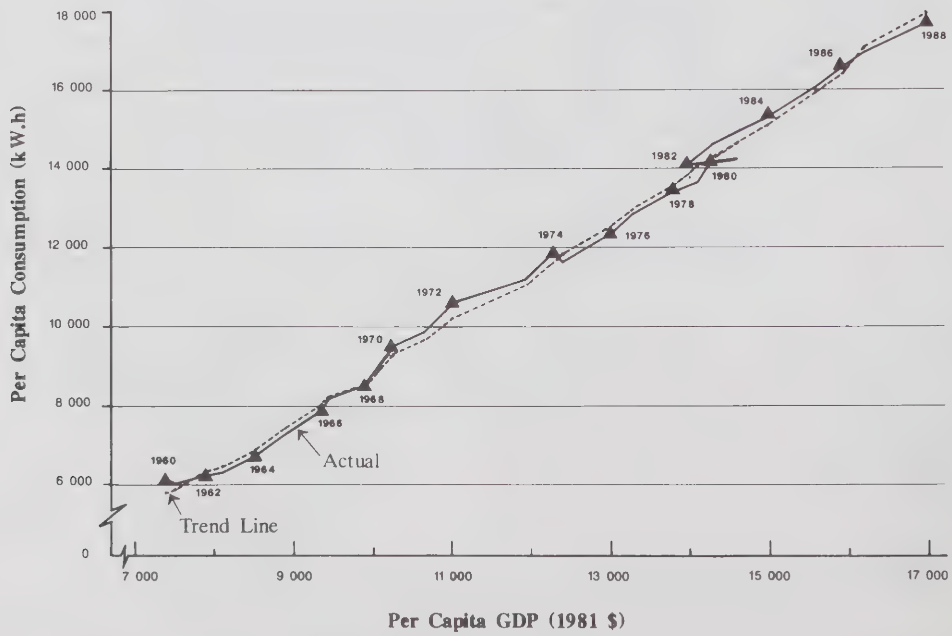


Table 3.4. Per capita electricity consumption by province

	Per capita consumption (kW.h/person)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1987	1988	1960-74	1975-88	1960-88	1987-88
Nfld.	3 184	5 500	9 226	11 304	14 758	16 632	16 745	18 347	10.1	3.8	6.5	9.6
P.E.I.	765	1 257	2 273	3 598	4 177	4 608	5 043	5 470	11.1	3.3	7.3	8.5
N.S.	2 385	3 310	4 739	6 948	7 988	8 668	9 370	10 083	7.9	2.9	5.3	7.6
N.B.	2 864	4 724	6 732	10 095	14 850	16 058	17 115	17 702	9.2	4.4	6.7	3.4
Que.	8 565	9 187	11 597	14 555	18 735	21 991	23 720	24 601	4.1	4.1	3.8	3.7
Ont.	6 086	7 259	9 203	10 915	12 422	13 510	14 205	14 917	4.3	2.4	3.3	5.0
Man.	4 932	6 158	8 750	11 726	13 521	14 863	14 649	15 550	6.3	2.2	4.2	6.2
Sask.	1 750	3 631	5 741	7 924	10 131	11 839	12 169	13 306	11.6	4.1	7.5	9.3
Alta.	2 695	3 864	6 194	8 575	11 135	14 120	15 277	16 378	8.4	5.1	6.7	7.2
B.C.	8 386	10 680	12 124	13 433	16 220	17 038	17 356	18 123	3.9	2.3	2.8	4.4
Yukon	4 589	7 569	11 957	16 526	17 085	10 862	18 633	17 352	8.7	0.4	4.9	-6.9
N.W.T.	5 304	5 540	8 851	10 316	11 052	11 647	9 174	8 996	3.5	-1.1	1.9	-1.9
Canada	6 184	7 339	9 501	11 718	13 112	16 043	17 121	17 796	4.9	3.3	3.8	3.9

Source: *Electrical Energy Branch, Energy, Mines and Resources Canada.*

Table 3.5. Peak demand by province*

	Peak demand (MW)								Average annual growth rate (per cent)			
	1960	1965	1970	1975	1980	1985	1987	1988**	1960-74	1975-88	1960-88	1987-88
Nfld.	245	422	763	1 031	1 538	1 510	1 674	1 740	12.5	4.1	7.3	3.9
P.E.I.	21	35	55	85	104	93	105	127	11.7	3.1	6.6	21.0
N.S.	356	457	814	998	1 197	1 360	1 543	1 706	8.6	4.2	5.8	10.6
N.B.	319	528	726	1 101	1 699	1 888	2 367	2 525	10.8	6.6	7.7	6.7
Que.	5 871	8 228	11 127	15 114	20 680	25 618	28 862	28 688	7.8	5.1	5.8	-0.6
Ont.	6 391	8 596	12 048	15 570	17 767	21 533	23 520	23 816	6.5	3.3	4.8	1.3
Man.	772	1 022	1 565	2 326	2 681	2 932	3 301	3 437	8.3	3.1	5.5	4.1
Sask.	418	653	1 028	1 318	2 085	2 202	2 201	2 280	9.7	4.3	6.3	3.6
Alta.	714	1 121	1 894	2 713	3 879	5 259	5 326	5 823	11.1	6.1	7.8	9.3
B.C.	2 123	3 058	4 492	5 797	7 384	8 487	8 759	8 054	8.2	2.6	4.9	-8.0
Yukon	19	16	39	66	75	53	68	75	9.4	1.0	5.0	10.3
N.W.T.	15	31	41	68	81	96	111	111	11.8	3.8	7.4	0.0
Canada	17 264	24 167	34 592	46 187	59 170	71 031	77 837	78 382	7.8	4.2	5.5	0.7

* *Peak demand is the annual maximum average net kilowatt load of one -hour duration within an electrical system.*
** *Preliminary data.*

Source: ***Electric Power Statistics, Volume I**, Statistics Canada, catalogue 57-204.*

Table 3.6. Load factor by province*

	1960	1965	1970	1975	1980	1985	1987	1988
				(per cent)				
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	66.1	68.4
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	70.3	63.3
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	61.6	59.6
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	59.7	57.2
Que.	85.6	72.5	71.5	67.9	65.3	64.5	62.6	65.0
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	64.2	67.4
Man.	59.5	66.4	62.7	58.4	59.3	62.0	54.9	56.0
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	64.6	67.4
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	78.4	77.1
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	66.4	76.6
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	72.5	66.8
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	48.0	47.9
Canada	72.3	68.1	66.8	65.7	65.6	65.1	64.3	67.2

* *Load factor is the energy demand in kilowatt-hours divided by the product of the number of hours in the period and multiplied by the peak demand in kilowatts. In a year-base average, demand equals annual energy consumption divided by 8760 hours per year.*

Source: Calculated from ***Electric Power in Canada, 1988****, Tables 3.1 and 3.5.*

4. ELECTRICITY GENERATION

Canada's electric power industry began in the 1880s with electricity generated by steam. In the early years, electricity was used mainly for home and street lighting. In the late-1880s and 1890s, the invention of the electric motor dramatically changed the industry from one that mainly provided nighttime power for lighting to one that also provided power for transportation and industry needs 24 hours a day. Following this, hydroelectric development spread rapidly, due to Canada's abundance of water resources. In 1920, hydro accounted for about 99 per cent of total electricity production in Canada. This percentage declined to 95 per cent by 1950 and 93 per cent by the end of 1960. By 1988, hydro production had further declined to 62 per cent (Table 4.1).

Although thermal generation, mainly from coal-fired stations, has been a part of Canada's generation mix since the beginning of the electric power industry, for many years its share of total production did not increase significantly because of its relatively high cost of production. However, by the 1960s and 1970s, when most of Canada's economical hydro sites had been developed, the situation changed, and thermal generation became competitive.

After 1975, nuclear production emerged as an important source of electricity generation in Canada. Canadian nuclear power began in 1962 when the 25-MW Rolphton station went into operation in Ontario. In 1965, nuclear generation totalled only 88 GW.h, accounting for less than 0.1 per cent of total generated electricity in Canada. By 1980, the nuclear-production share increased to about 10 per cent of Canada's total, and by 1988 the percentage increased to 16 per cent.

To date, tidal power has played an insignificant role in electricity generation in Canada. However, it is worth noting that the 20-MW Annapolis tidal power plant in Nova Scotia, which began operation in 1984, is the first of its kind in North America.

Because of the rapid expansion of coal-fired stations in the 1960s and 1970s, coal consumption increased more than 28 times between 1960 and 1988 (Table 4.4). Most of the coal used for electricity generation is produced in Canada, with the exception of Ontario, where a large proportion is imported from the United States.

Oil is mainly used for peak-load generation, except in the Atlantic provinces and the Yukon and Northwest territories. Natural gas is used by industry for co-generation and by electric utilities for peak-load generation.

Table 4.1. Sources of electricity generation

	Electricity Generation								Average Annual Growth Rate			
Fuel Type	1960	1965	1970	1975	1980	1985	1987	1988	1960-1974	1975-1988	1960-1988	1987-1988
	(GW.h)								(per cent)			
Hydro	105 883	117 063	156 709	202 396	251 217	301 250	313 156	303 524	5.1	3.2	3.8	-3.1
Thermal	8 495	27 123	47 045	59 138	80 207	88 842	96 031	107 322	14.3	4.7	9.5	11.8
Nuclear*	—	88	969	11 858	35 882	57 067	72 888	78 176	—	15.6	—	7.3
Tidal**	—	—	—	—	—	23	33	22	—	—	—	-16.7
Total	114 378	144 274	204 723	273 392	367 306	447 182	482 108	489 044	6.6	4.6	5.3	1.4

* *Commercial operation started in 1968.*
** *Commercial operation started in 1984.*

Source: ***Electric Power Statistics, Volume II**, Statistics Canada, Catalogue 57-202.*

Figure 4.1. Major generating stations by province, 1988

Figure 4.2. Electricity generation by fuel type

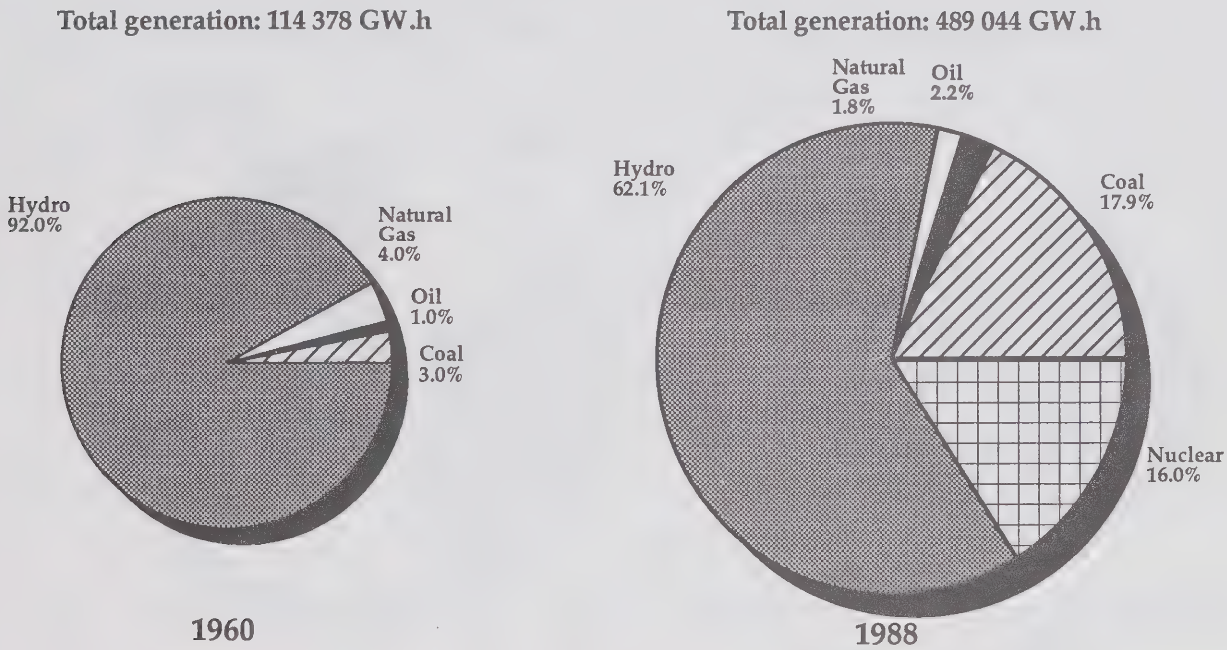


Table 4.2. Electrical energy production by fuel type, 1988

	Coal	Oil	Natural Gas	Nuclear	Hydro	Total
				(GW.h)		
Newfoundland	0	1 419	0	0	39 731	41 150
Prince Edward Island	133	85	0	0	0	218
Nova Scotia	6 033	1 752	0	0	1 107	8 892
New Brunswick	1 732	6 118	0	5 342	2 580	15 772
Quebec	0	332	0	5 282	143 391	149 005
Ontario	35 033	510	1 334	67 552	38 314	142 743
Manitoba	924	0	5	0	15 379	16 308
Saskatchewan	9 853	19	722	0	2 343	12 937
Alberta	33 627	120	4 994	0	1 431	40 172
British Columbia	0	420	1 949	0	58 573	60 942
Yukon	0	30	0	0	409	439
Northwest Territories	0	177	1	0	288	466
Canada	87 335	10 982	9 005	78 176	303 546	489 044

Source: Energy, Mines and Resources Canada.

Figure 4.3. Electricity generation by region

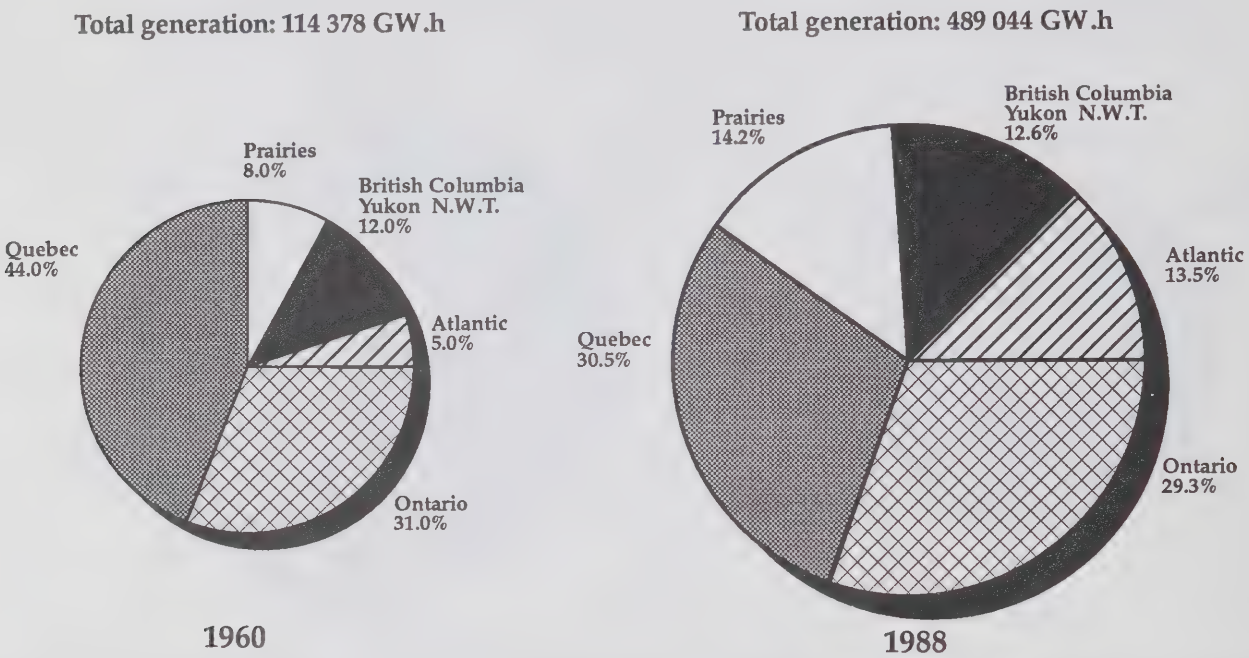


Table 4.3. Electricity generation by province

	Electricity Generation								Average Annual Growth Rate			
	1960	1965	1970	1975	1980	1985	1987	1988	1960-1974	1975-1988	1960-1988	1987-1988
	(GW.h)								(per cent)			
Nfld.	1 512	2 769	4 854	35 803	46 374	41 494	40 090	41 150	23.4	1.1	12.5	2.6
P.E.I.	79	137	250	421	127	2	164	218	11.9	-4.9	3.7	32.9
N.S.	1 814	2 632	3 511	5 498	6 868	7 457	7 749	8 892	8.2	3.8	5.8	14.8
N.B.	1 738	2 960	5 142	4 677	9 323	11 401	12 493	15 772	8.7	9.8	8.2	26.2
Quebec	50 433	57 005	75 877	76 108	97 917	137 028	156 952	149 005	3.7	5.3	3.9	-5.1
Ontario	35 815	44 858	63 857	78 558	110 283	121 783	131 582	142 743	6.2	4.7	5.1	8.5
Manitoba	3 742	5 489	8 449	14 818	19 468	22 777	19 902	16 308	10.2	0.7	5.4	-18.1
Sask.	2 204	3 733	6 011	7 090	9 204	11 838	12 440	12 937	9.0	4.7	6.5	4.0
Alberta	3 443	5 591	10 035	15 100	23 451	33 432	36 770	40 172	10.8	7.8	9.2	9.3
B.C.	13 409	18 832	26 209	34 542	43 416	59 124	63 067	60 942	7.4	4.5	5.6	-3.4
Yukon	89	121	224	352	381	252	432	439	9.3	1.7	5.9	1.6
N.W.T.	100	147	304	425	494	594	467	466	10.2	0.7	5.7	-0.2
Canada	114 378	144 274	204 723	273 392	367 306	447 182	482 108	489 044	6.6	4.6	5.3	1.4

Source: ***Electric Power Statistics, Volume II****, Statistics Canada, Catalogue 57-202.*

Table 4.4. Fuels used to generate electricity in Canada

	1960	1965	1970	1975	1980	1985	1987	1988*
Coal (10^3 tonnes)	1 674	7 004	13 786	16 567	27 785	39 456	43 332	47 443
Oil (10^3 cubic metres)	328	871	1 869	2 309	2 867	1 391	2 048	2 454
Natural gas (10^6 cubic metres)	1 069	1 679	1 992	4 009	1 875	1 223	2 847	3 628
Uranium (tonnes)	0	2	16	194	685	1 086	1 303	1 358

* *Preliminary data.*

Source: *Electric Power Statistics, Volume II*, *Statistics Canada, Catalogue 57-202.*

Table 4.5. Fossil fuels used by utilities, 1988

	Coal (10^3 tonnes)	Oil (cubic metres)	Gas (10^6 cubic metres)	Uranium (tonnes)
Nfld.	0	368 006	0	0
P.E.I.	51	37 700	0	0
N.S.	2 266	393 051	0	0
N.B.	663	1 369 114	0	98
Que.	0	55 905	0	99
Ont.	14 473	156 432	1 141	1 161
Man.	768	548	9	0
Sask.	8 637	4 801	265	0
Alta.	20 585	30	2 077	0
B.C.	0	85	122	0
Yukon	0	8 410	0	0
N.W.T.	0	60 005	14	0
Canada	47 443	2 454 087	3 628	1 358

Note: 1 cubic metre oil = 6.3 barrels
1 cubic metre gas = 35.5 cubic feet
1 tonne = 1000 kilograms

Source: Energy, Mines and Resources Canada.

5. GENERATING CAPACITY AND RESERVE

Although Canada's first electrical generating stations were thermal, by 1920 hydro accounted for 86 per cent of total generating capacity. With growing demand, hydroelectric power quickly proved to be more economical than thermal, and by 1945 hydro's share of total installed capacity peaked at 94 per cent. Its capacity share then declined to about 81 per cent by 1960, and declined further to 56 per cent by 1988 (Table 5.1).

Several factors have contributed to the gradual reduction of the hydro capacity share since 1960. By that date most of Canada's economic hydro sites had been developed. Moreover, the growth rates of real fossil-fuel prices (coal, oil and natural gas) were negative between 1950 and 1974, thus leading many utilities to construct thermal stations during this period.

In addition, in the early 1960s, Canada began to develop nuclear energy as an alternative source for future energy demand. By 1988, Canada owned and operated 18 large CANDU reactors (500 MW and up). CANDU's have been shown to be among the best nuclear reactors in the world in terms of cost-effectiveness, safety measures, and output performance (Figure 5.3).

As indicated in Chapter 3, electricity consumption in Canada grew rapidly from 1960 to 1974, with an average annual increase of 6.6 per cent. In the early 1970s, the construction of new generating stations was initiated based on expectations of continuing rapid growth in electricity demand, and also to displace oil-fuelled electricity production. Following the oil crisis of 1973-74, however, electricity demand slowed to an average of 4.3 per cent for the period 1975-88. This shift, from a long period of sustained rapid growth to one of slower growth, has resulted in excess generating capacity (Table 5.8).

There is still a large amount of undeveloped hydroelectric potential in Canada (Table 5.9 and Appendix C). Although much of this is unlikely to be developed due to the remoteness of the sites, the physical difficulty of the terrain, or because of environmental concerns, it is anticipated that a significant amount will be developed over the next 20 to 25 years. Quebec, British Columbia, Manitoba and Newfoundland have most of the remaining river potential. Tidal resources are located in Nova Scotia, Quebec and British Columbia.

Table 5.1. Installed generating capacity by fuel type, 1960-1988

Fuel Type	Installed Generating Capacity								Average Annual Growth Rate			
	1960	1965	1970	1975	1980	1985	1987	1988	1960-1974	1975-1988	1960-1988	1987-1988
	(MW)								(per cent)			
Hydro	18 643	21 771	28 298	37 282	47 770	57 711	57 925	57 464	5.0	3.4	4.1	-0.8
Thermal	4 392	7 557	14 287	21 404	28 363	30 476	30 800	30 914	11.7	2.9	7.2	0.4
Nuclear*	0	20	240	2 666	5 866	10 664	12 528	12 528	-	12.6	-	0.5
Tidal**	0	0	0	0	0	20	20	20	-	-	-	0.0
Total	23 035	29 348	42 826	61 352	81 999	97 020	100 273	100 984	6.8	3.9	5.4	-0.3

* *Commercial operation started in 1968.*
** *Commercial operation started in 1984.*

Source: ***Electric Power Statistics, Volume II****, Statistics Canada, Catalogue 57-202*

Figure 5.1. Installed generating capacity by fuel type

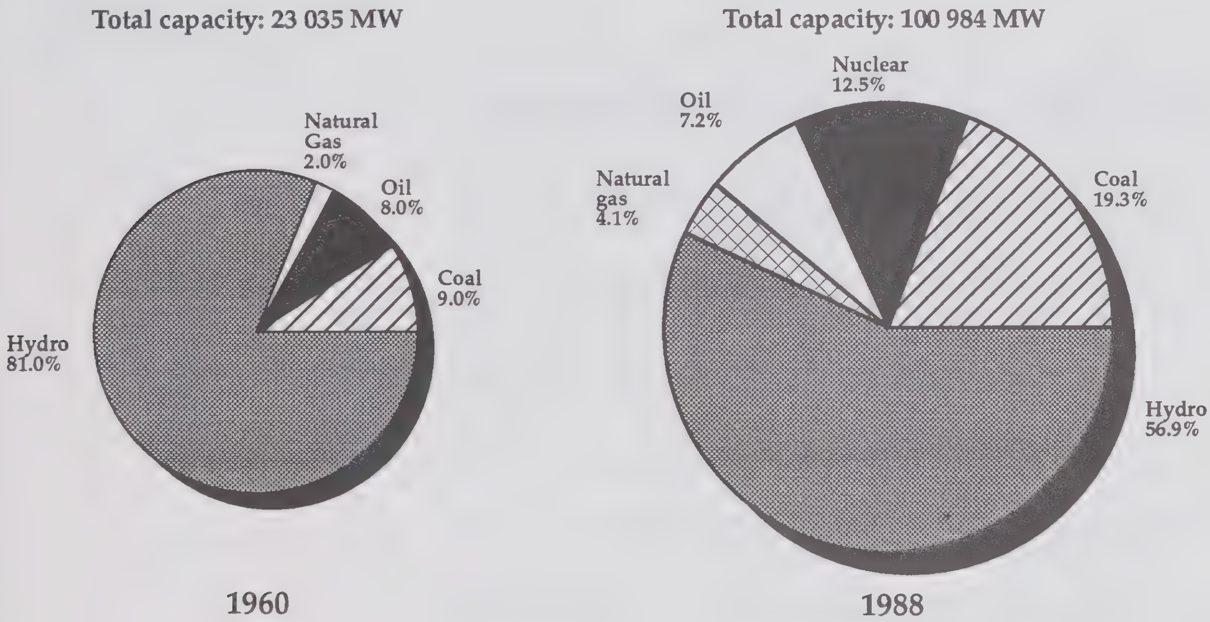


Figure 5.2. Installed generating capacity by region

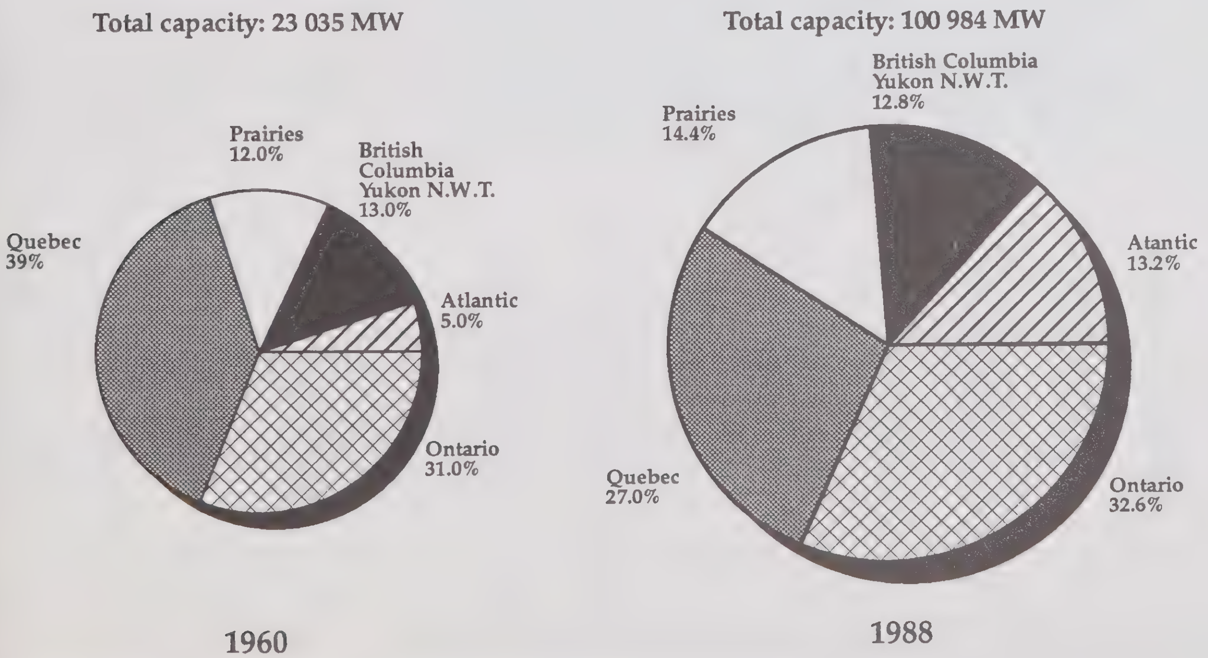


Table 5.2. Installed generating capacity by fuel type and province, 1988

	Hydro	Coal	Nuclear	Oil	Natural Gas	Total
				(MW)		
Nfld.	6 644	0	0	782	0	7 426
P.E.I.	0	20	0	122	0	142
N.S.	386	1 201	0	758	0	2 345
N.B.	903	356	680	1 532	0	3 471
Que.	25 585	0	685	980	8	27 258
Ont.	7 775	10 935	11 221	2 651	373	32 955
Man.	3 641	466	0	14	4	4 125
Sask.	832	1 554	0	27	432	2 845
Alta.	734	4 979	0	15	1 872	7 600
B.C.	10 848	0	0	246	1 403	12 497
Yukon	82	0	0	44	19	145
N.W.T.	54	0	0	121	20	175
Canada	57 484	19 511	12 586	7 292	4 111	100 984

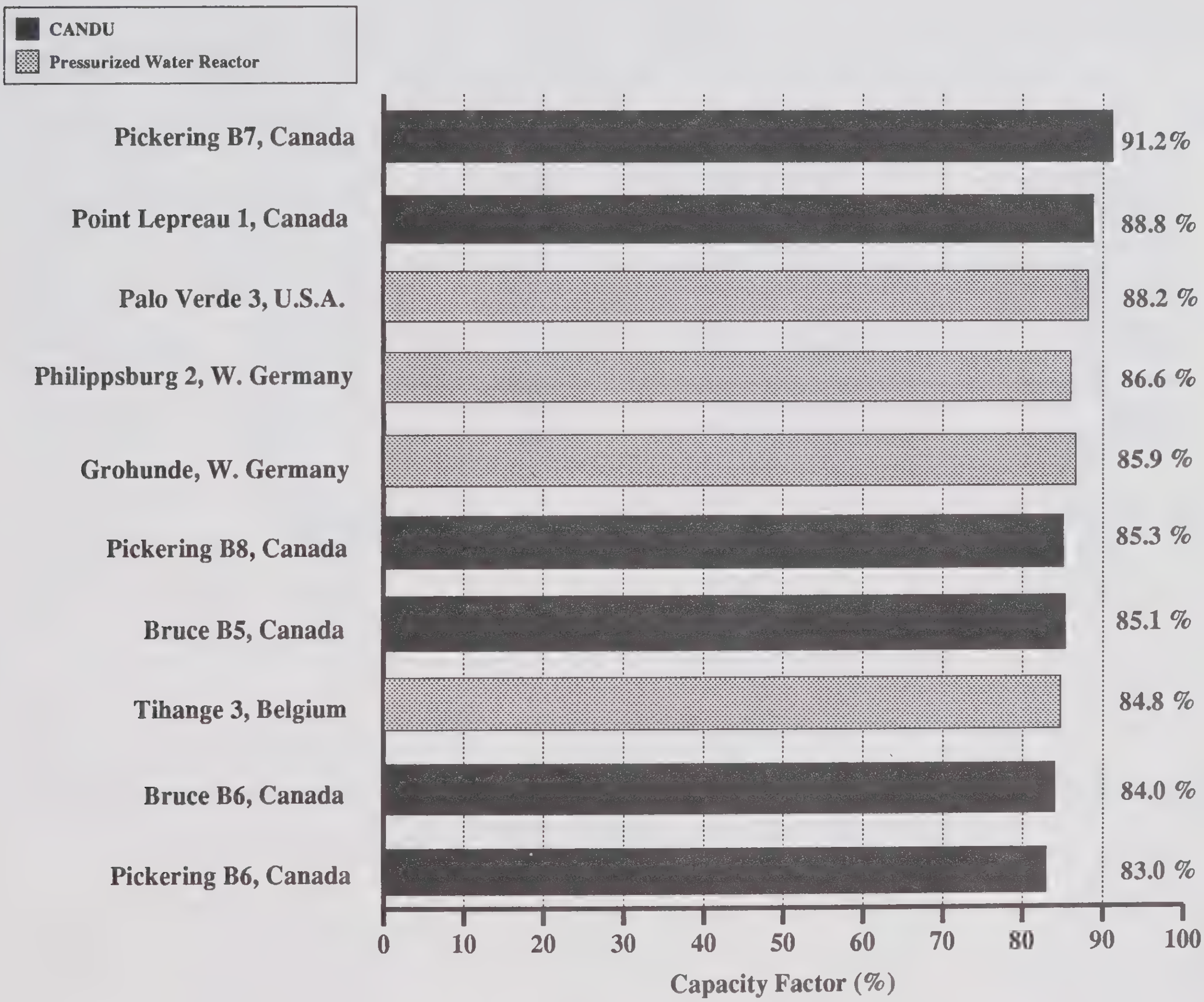
Source: Electric Power Statistics, Volume II, Statistics Canada, Catalogue 57-204.
Energy, Mines and Resources Canada.

Table 5.3. Installed generating capacity by province, 1960-1988

	Installed Generating Capacity								Average Annual Growth Rate			
	1960	1965	1970	1975	1980	1985	1987	1988	1960-1974	1975-1988	1960-1988	1987-1988
	(MW)								(per cent)			
Nfld.	314	531	1 248	6 668	7 195	7 316	7 401	7 426	21.4	0.8	12.0	0.3
P.E.I.	37	58	77	118	118	122	142	142	8.6	1.4	4.9	0.0
N.S.	507	631	931	1 263	2 029	2 373	2 345	2 345	6.4	4.9	5.6	0.0
N.B.	402	581	1 201	1 333	2 795	3 479	3 471	3 471	8.9	7.6	8.0	0.0
Quebec	8 920	10 769	14 047	15 037	20 531	26 991	27 827	27 258	3.7	4.7	4.1	-2.0
Ontario	7 109	9 292	13 700	21 136	25 796	29 932	32 703	32 955	7.0	3.5	5.6	0.8
Manitoba	1 043	1 407	1 794	2 970	4 142	4 141	4 125	4 125	7.8	2.6	5.0	0.0
Sask.	761	967	1 533	1 833	2 340	2 694	2 845	2 845	6.2	3.4	4.8	0.0
Alberta	915	1 398	2 674	3 585	5 807	7 219	7 600	7 600	9.9	6.0	7.9	0.0
B.C.	2 963	3 627	5 473	7 170	10 525	12 451	12 497	12 497	6.0	4.4	5.3	0.0
Yukon	31	56	58	102	94	123	142	145	5.6	2.7	5.7	2.1
N.W.T.	33	51	89	136	180	177	175	175	9.3	2.0	6.1	0.0
Canada	23 035	29 348	42 826	61 352	81 999	97 019	101 273	100 984	6.8	3.9	5.4	-0.3

Source: Electric Power Statistics, Volume II, Statistics Canada, Catalogue 57-202.

Figure 5.3. World nuclear reactor performance —lifetime* (to December 31, 1988)



* *All nuclear reactors used in comparison are greater than 500 MW. COMECON countries are excluded. The lifetime performance is calculated from the first day of electricity generation.*

Source: Uranium and Nuclear Energy Branch, Energy, Mines and Resources Canada.

Table 5.4. Canada's largest hydro stations, 1988

Rank	Name	Province	Rated Capacity (MW)	Year of Initial Operation
1	Churchill Falls	Newfoundland	5 429	1971
2	La Grande 2	Quebec	5 328	1979
3	La Grande 4	Quebec	2 651	1984
4	Gordon M. Shrum	B.C.	2 416	1968
5	La Grande 3	Quebec	2 302	1982
6	Revelstoke	B.C.	1 843	1984
7	Mica	B.C.	1 736	1976
8	Beauharnois	Quebec	1 639	1932
9	Manic 5	Quebec	1 292	1970
10	Sir Adam Beck 2	Ontario	1 288	1954

Source: Electric Power Statistics, Volume III, Statistics Canada, Catalogue 57-206, 1987.

Table 5.5. Canada's largest conventional thermal stations, 1988

Rank	Name	Fuel Type	Province	Rated Capacity (MW)	Year of Initial Operation
1	Nanticoke	coal	Ontario	4 096	1973
2	Lakeview	coal	Ontario	2 400	1962
3	Lennox	oil	Ontario	2 295	1976
4	Sundance	coal	Alberta	2 200	1970
5	Lambton	coal	Ontario	2 000	1969
6	Richard L. Hearn	coal	Ontario	1 200	1951
7	Coleson Cove	oil	N.B.	1 050	1976
8	Burrard	natural gas	B.C.	913	1962
9	Boundary Dam	coal	Saskatchewan	874	1959
10	Keephills	coal	Alberta	806	1983

*Source: **Electric Power Statistics, Volume III**, Statistics Canada, Catalogue 57-206, 1987.*

Table 5.6. Commercial nuclear power plants in Canada, 1988

	Plant Name	Province	Rated Net Capacity (MW)	Commissioning Date
1	Pickering A1	Ontario	515	1971
2	Pickering A2	Ontario	515	1971
3	Pickering A3	Ontario	515	1972
4	Pickering A4	Ontario	515	1973
5	Bruce A1	Ontario	759	1977
6	Bruce A2	Ontario	769	1977
7	Bruce A3	Ontario	759	1978
8	Bruce A4	Ontario	769	1979
9	Point Lepreau 1	New Brunswick	635	1983
10	Pickering B5	Ontario	516	1983
11	Gentilly 2	Quebec	638	1983
12	Pickering B6	Ontario	516	1984
13	Bruce B6	Ontario	837	1984
14	Pickering B7	Ontario	516	1985
15	Bruce B5	Ontario	835	1985
16	Pickering B8	Ontario	516	1986
17	Bruce B7	Ontario	837	1986
18	Bruce B8	Ontario	837	1987

Source: *Uranium and Nuclear Energy Branch, Energy, Mines and Resources Canada.*

Table 5.7. Surplus capacity, 1988*

	Net Generating Capability for In-Province Use (MW) (1)	In-Province Firm peak (MW) (2)	Reserve Margin (MW) (3) = (1) - (2)	Percentage of Reserve (4) = (3) / (2)
Nfld.	2 072	1 917	1 055	55
P.E.I.	135	110	25	23
N.S.	2 019	1 574	445	22
N.B.	3 135	2 352	783	33
Que.	31 342	27 060	4 282	16
Ont.	28 750	23 672	5 078	22
Man.	4 335	3 345	990	30
Sask.	2 744	2 299	445	19
Alta.	7 387	5 611	1 776	32
B.C.	12 540	9 072	3 468	38
Yukon	122	69	53	77
N.W.T.	188	111	77	69
Canada	95 605	77 192	18 477	24

* *Preliminary data.*
Source: ***Electric Power Statistics, Volume I**, Statistics Canada, Catalogue 57-204.*

Table 5.8. Surplus capacity percentages, 1960-1988

	1960	1965	1970	1975	1980	1985	1987	1988
				(per cent)				
Nfld.	20	17	55	48	98	101	79	55
P.E.I.	81	66	33	33	13	40	33	23
N.S.	39	32	13	18	62	38	31	22
N.B.	17	9	49	34	33	51	15	33
Que.	37	16	16	10	14	20	21	16
Ont.	14	6	13	26	34	11	30	22
Man.	32	41	24	18	54	48	18	30
Sask.	60	28	26	30	7	15	22	19
Alta.	30	23	38	32	45	36	39	32
B.C.	43	19	23	30	49	50	43	38
Yukon	42	100	23	58	29	130	78	77
N.W.T.	87	48	42	46	51	70	68	69
Canada	28	15	19	25	31	26	21	24

Source: Calculated from ***Electric Power Statistics, Volume I****, Statistics Canada, Catalogue 57-204.*

Table 5.9. Hydroelectric capacity in Canada, 1988

Province or Territory	In-Operation and Under Construction	Remaining Potential Gross*	Remaining Potential Identified**	Remaining Potential Planning***
		(MW		
Newfoundland	6 675	5 201	4 623	2 395
Prince Edward Island	0	0	0	0
Nova Scotia	386	8 499	8 499	0
New Brunswick	903	940	600	440
Quebec	28 541	71 008	39 566	17 964
Ontario	7 775	12 385	12 305	4 024
Manitoba	4 921	8 190	5 090	5 090
Saskatchewan	830	2 189	935	870
Alberta	734	18 813	9 762	1 923
British Columbia	10 848	33 154	18 185	10 555
Yukon	82	18 583	13 701	350
Northwest Territories	50	9 229	9 201	2 473
Canada	61 745	188 191	122 467	46 084

* *Gross Potential - The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).*

** *Identified Potential - Gross potential less sites that may not be developed for technical reasons.*

*** *Planning Potential - Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.*

Source: Canadian electrical utilities and Energy, Mines and Resources Canada.

6. ELECTRICITY TRADE

This chapter reports on electricity trade between Canada and the United States and on interprovincial electricity transfers.

Electricity exchanges between Canada and the United States date back to the beginning of the century. For most of the century, electricity trade between the two countries was balanced. However, between the early 1970s and 1988, Canada's net exports grew substantially, largely due to the high cost of thermal production (particularly oil-fired generation) in the United States.

Preliminary data for 1988, however, indicate that electricity exports to the United States decreased by 27 per cent for revenue, and 29 per cent for volume over 1987 (Table 6.5). (The decrease is mainly attributed to drought conditions and higher domestic demand.) Although all major exporters experienced lower sales this year, the greatest reductions occurred in Quebec and British Columbia. Export reductions in these two provinces amounted to two-thirds of the total decrease in exports. Both provinces had significantly less hydraulic energy available for economy energy sales than in previous years.

In 1988, the major export markets for Canadian electricity were New England and New York. The former accounted for about 34 per cent of Canada's total exports, and the latter 31 per cent.

In 1988, interprovincial exchanges totalled 41 517 GW.h, which accounted for about 8.5 per cent of Canada's total generation (Table 6.11).

Figure 6.1. Net electricity exports and Canadian merchandise trade balance, 1988

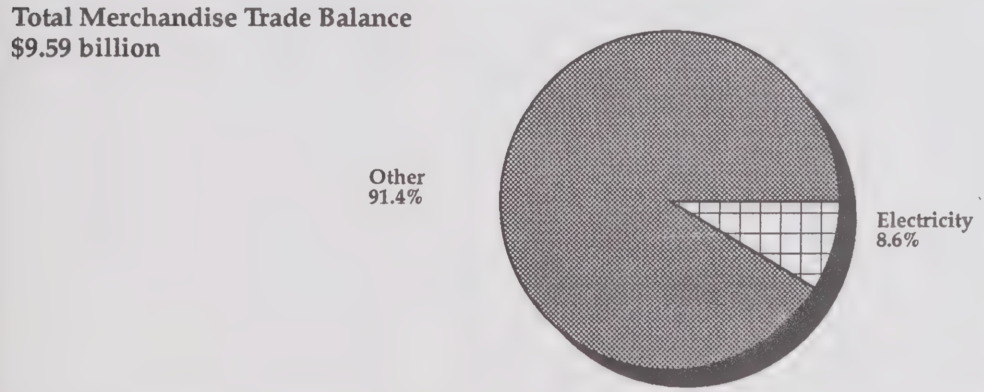


Figure 6.2 Net electricity exports and Canadian energy trade balance, 1988

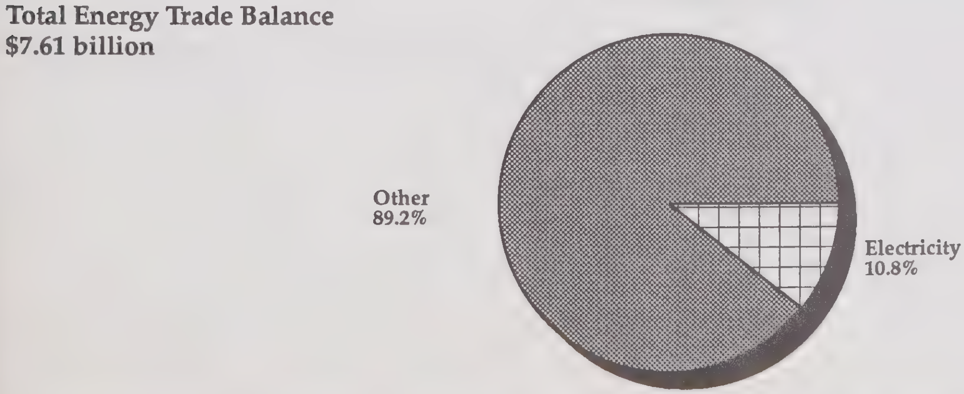


Table 6.1. Canada-U.S. electricity trade, 1960-1988

	Exports* (GW.h) (1)	Exports as a percentage of net generation (2)	Export revenues ($million) (3)	Imports* (GW.h) (4)	Imports as a percentage of total disposal (5)	Import costs ($million) (6)	Net Exports GW.h (7) = (1) - (4)	Net Exports $Million (8) = (3) - (6)
1960	5 496	4.8	14	357	0.3	1	5 139	13
1961	4 158	3.7	10	1 394	1.3	2	2 764	8
1962	4 112	3.5	8	2 779	2.4	3	1 333	5
1963	3 613	3.0	7	2 884	2.4	3	729	4
1964	4 159	3.1	10	3 121	2.3	3	1 038	7
1965	3 684	2.6	8	3 575	2.5	3	109	5
1966	4 397	2.8	8	3 218	2.1	3	1 179	5
1967	3 994	2.4	8	4 181	2.6	6	-187	2
1968	3 988	2.1	8	4 129	2.3	6	-141	2
1969	4 320	2.3	15	2 740	1.5	3	1 580	12
1970	5 631	2.8	32	3 245	1.6	9	2 386	23
1971	7 321	3.4	45	3 378	1.6	8	3 943	37
1972	11 037	4.6	66	2 381	1.0	3	8 656	63
1973	16 286	6.2	115	2 249	0.9	1	14 037	114
1974	15 400	5.5	169	2 441	0.9	1	12 959	168
1975	11 409	4.2	105	3 972	1.5	3	7 819	102
1976	12 804	4.4	174	3 590	1.3	7	9 214	167
1977	19 957	6.3	419	2 690	0.9	13	17 267	406
1978	20 437	6.1	479	170	0.1	2	20 267	477
1979	30 458	8.6	739	24	0.0	1	30 434	738
1980	28 224	7.7	794	168	0.1	3	28 056	791
1981	34 730	9.1	1 144	466	0.1	5	34 264	1 138
1982	32 986	8.8	1 107	257	0.1	5	32 729	1 102
1983	37 258	9.4	1 249	239	0.1	6	37 019	1 243
1984	37 563	8.8	1 355	290	0.1	10	37 272	1 345
1985	41 441	9.3	1 425	231	0.1	9	41 210	1 416
1986	35 271	8.5	1 086	235	0.1	9	35 036	1 077
1987	45 359	9.4	1 211	536	0.1	12	44 823	1 199
1988	29 729	6.1	880	2 853	0.6	63	26 876	817

* *Exports and imports prior to 1977 include service exchanges.*

Source: ***Electric Power Statistics, Volume II****, Catalogue 57-202, Statistics Canada. Energy, Mines and Resources Canada.*

Table 6.2. Electricity exports to the United States by type, 1960-1988

	Quantity (GW.h)		Revenue ($1000)		Quantity share (%)		Revenue share (%)	
	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible	Firm	Interruptible
1960	1 040	4 456	4 328	10 023	19	81	30	70
1961	1 192	2 965	5 769	3 783	29	71	60	40
1962	1 261	2 851	6 487	1 775	31	69	79	21
1963	882	2 730	4 625	2 028	24	76	70	30
1964	871	3 289	5 561	4 359	21	79	56	44
1965	635	3 049	4 261	3 322	17	83	56	44
1966	614	3 783	4 257	3 402	14	86	56	44
1967	705	3 289	4 663	3 068	18	82	60	40
1968	741	3 247	5 003	2 714	19	81	65	35
1969	838	3 482	5 735	9 279	19	81	38	62
1970	984	4 648	6 828	25 309	18	82	21	79
1971	1 860	5 461	13 270	31 951	25	75	29	71
1972	2 047	8 990	19 198	46 846	19	81	29	71
1973	2 637	13 649	19 891	94 947	16	84	17	83
1974	2 488	12 912	20 939	147 945	16	84	12	88
1975	2 375	9 034	20 382	84 488	21	79	19	81
1976	2 061	10 743	39 010	134 755	16	84	22	78
1977	3 727	16 230	90 220	329 050	19	81	22	78
1978	3 980	16 457	94 543	384 011	20	80	20	80
1979	6 692	23 766	135 763	602 740	22	78	18	82
1980	7 232	20 992	156 731	636 760	26	74	20	80
1981	5 008	29 722	105 116	1 038 761	14	86	9	91
1982	5 831	27 154	243 140	863 558	18	82	22	78
1983	10 569	26 689	445 751	802 806	28	72	36	64
1984	10 852	26 711	491 662	863 057	29	71	36	64
1985	12 305	29 136	547 109	877 657	30	70	38	62
1986	9 745	25 526	480 233	605 254	28	72	44	56
1987	8 840	36 519	354 781	856 068	19	81	29	71
1988	8 331	21 398	327 132	553 406	28	72	37	63

Source: ***Electric Power Statistics, Volume II****, Catalogue 57-202, Statistics Canada.Energy, Mines and Resources Canada.*

Table 6.3. Average export revenues, 1960-1988

Year	Firm	Interruptible	Total
		(mills/kW.h)	
1960	4.2	2.3	2.6
1961	4.8	1.3	2.3
1962	5.1	0.6	2.0
1963	5.2	0.7	1.8
1964	6.4	0.9	2.4
1965	6.7	1.1	2.1
1966	6.9	0.9	1.7
1967	6.6	0.9	1.9
1968	6.8	0.8	1.9
1969	6.8	2.7	3.5
1970	6.9	5.5	5.7
1971	7.1	5.9	6.2
1972	9.4	5.2	6.0
1973	7.5	7.0	7.1
1974	8.4	11.5	11.0
1975	8.6	9.4	9.2
1976	18.9	12.5	13.6
1977	24.2	20.3	21.0
1978	23.8	23.3	23.4
1979	20.3	25.4	24.3
1980	21.7	30.3	28.1
1981	21.0	34.9	32.9
1982	41.7	31.8	33.6
1983	42.2	30.1	33.5
1984	45.3	32.3	36.1
1985	44.5	30.1	34.4
1986	49.3	23.7	30.8
1987	40.1	23.4	26.7
1988	39.3	25.9	29.6

Source: Calculated from Electric Power in Canada, 1988, Table 6.2.

Table 6.4. Generation sources of Canadian exports, 1975-1988

	Hydro	Imported Coal	Imported Oil	Domestic Coal/Oil	Nuclear	Total
			(GW.h)			
1975	5 724	4 838	494	353	0	11 409
1976	6 973	4 323	1 206	302	0	12 804
1977	7 926	8 514	2 961	555	0	19 957
1978	7 290	10 476	2 260	411	0	20 437
1979	15 213	11 587	3 354	128	177	30 458
1980	14 135	10 599	2 867	593	30	28 224
1981	21 182	10 901	1 940	665	42	34 730
1982	20 114	10 315	1 959	502	96	32 986
1983	21 978	11 704	1 201	519	1 856	37 258
1984	22 807	10 582	1 552	711	1 911	37 563
1985	28 836	8 245	1 157	956	2 247	41 441
1986	25 727	5 389	846	825	2 484	35 271
1987	34 065	7 575	1 270	408	2 041	45 359
1988	19 621	4 531	1 393	2 033	2 151	29 729

Source: *Compiled from National Energy Board statistics.*

Table 6.5. Electricity exports and revenues by province, 1987-1988*

	Quantity (GW.h)			Revenue (million $)			Average Revenue (mills/kW.h)		
	1987	1988	% Change	1987	1988	% Change	1987	1988	% Change
N.B.	5 910	5 052	-15	278.0	223.2	-20	47.1	44.2	-6
Que.	16 400	11 865	-28	445.4	345.6	-22	27.2	29.1	7
Ont.	7 194	5 623	-22	215.6	170.6	-21	30.0	30.3	1
Man.	3 314	723	-78	65.3	20.2	-69	19.7	27.9	42
Sask.	11	2	-82	0.2	0.03	-85	15.8	15.0	-5.1
B.C.	12 486	6 464	-48	206.4	120.8	-42	16.5	18.7	13
Canada	45 359	29 729	-35	1 210.9	880.5	-27	26.7	29.6	11

* *Excludes non-cash exchanges.*

Source: National Energy Board.

Table 6.6. Firm and interruptible exports, 1988*

	Firm	Interruptible	Firm	Interruptible
	(GW.h)		(per cent)	
New Brunswick	2 522	2 530	50	50
Quebec	4 921	6 944	41	59
Ontario	384	5 239	7	93
Manitoba	343	381	47	53
Saskatchewan	-	2	-	100
British Columbia	161	6 303	2	98
Canada	8 331	21 398	28	72

* *Exchanges are excluded.*

Source: National Energy Board.

Table 6.7. Energy sources of electricity exports, 1988

	Oil	Coal	Nuclear	Hydro	Other*	Total
			(per cent)			
New Brunswick	28	18	40	14	-	100
Quebec	-	-	-	100	-	100
Ontario	3	81	2	13	1	100
Manitoba	-	1	-	29	70	100
Saskatchewan	-	100	-	-	-	100
British Columbia	-	14	-	86	-	100
Canada	5	22	7	64	2	100

* *Refers to U.S. electricity imports that are subsequently exported.*

Source: Energy, Mines and Resources Canada.

Table 6.8. Exporting provinces and importing markets, 1988*

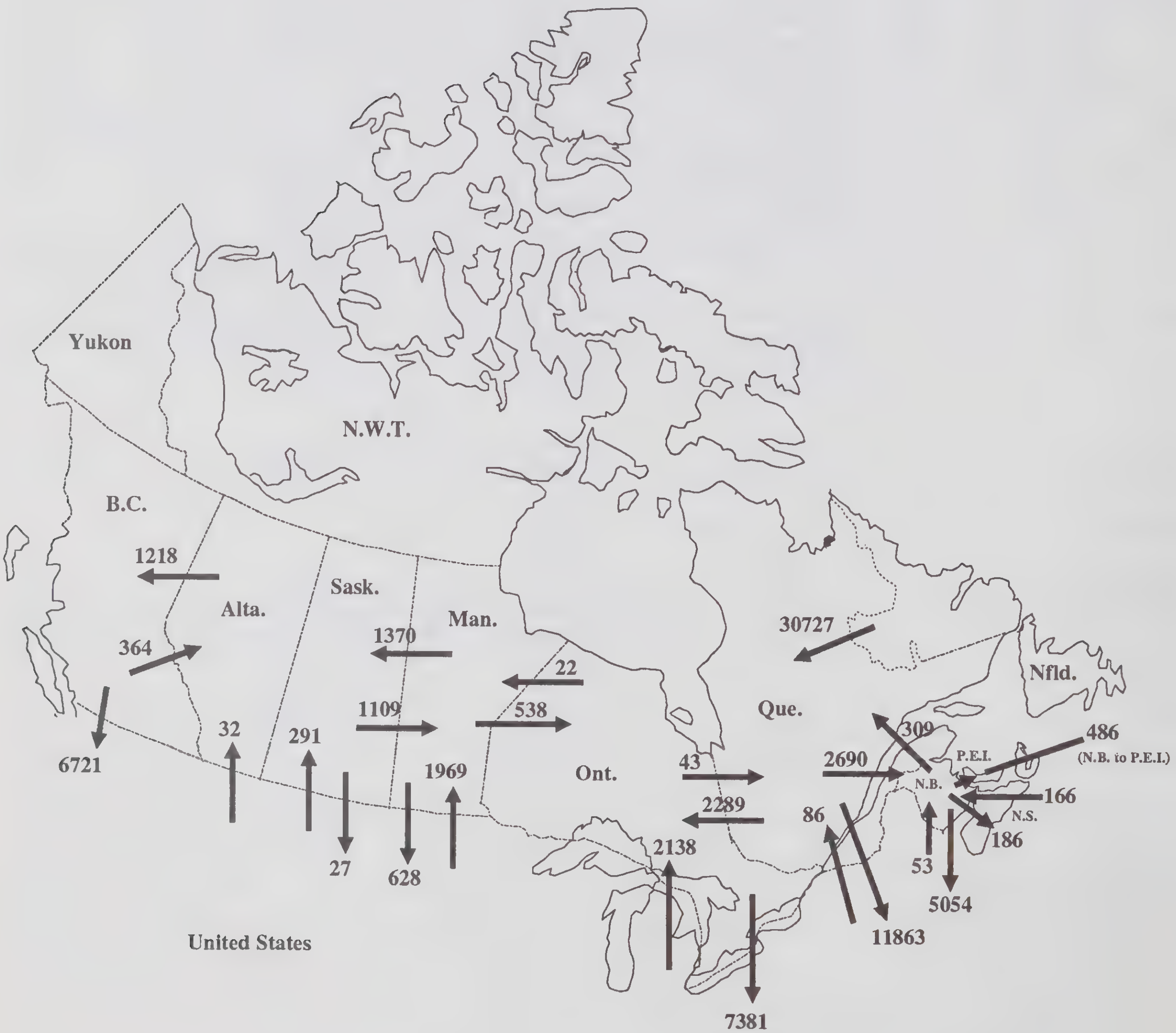
Exporting Province	Importing Market	Quantity (MW.h)	Value ($1000)
New Brunswick	Maine	3 091 008	110 144
	Massachusetts	1 914 790	108 413
	New Hampshire	43 080	4 031
	New England	4 080	632
Quebec	Maine	903	51
	Massachusetts	278 899	11 932
	New Hampshire	10	1
	Vermont	1 789 215	65 480
	New England	3 931 267	111 407
	New York	5 863 932	156 810
Ontario	Vermont	400 848	14 681
	New York	4 835 344	145 523
	Michigan	382 804	10 248
	Minnesota	3 820	173
Manitoba	Minnesota	659 787	18 546
	North Dakota	63 675	1 619
Saskatchewan	North Dakota	1 475	27
British Columbia	Washington	1 067 410	24 475
	Oregon	2 997 293	42 406
	Idaho	74 310	1 471
	Montana	5 503	116
	California	2 269 248	51 253
	Nevada	41 403	836
	Utah	8 588	191
	Alaska	534	71
Canada	United States	29 729 226	880 537

* *Excludes non-cash exchanges.*

Source: National Energy Board.

Figure 6.3. Electricity trade, 1988 (GW.h)*

Interprovincial transfers:	49 201 GW.h
Exports to U.S.:	31 673 GW.h
Imports from U.S.:	4 470 GW.h



* *Includes non- cash exchanges*

Table 6.9. Provincial shares of Canadian electricity exports, 1960-1988*

Year	New Brunswick	Quebec	Ontario	Manitoba	Saskatchewan	British Columbia	Canada
1960	3.0	10.4	86.6	0.0	0.0	0.0	100.0
1961	4.9	9.8	84.8	0.0	0.0	0.5	100.0
1962	6.0	7.2	86.4	0.0	0.0	0.4	100.0
1963	6.8	0.7	91.8	0.0	0.0	0.7	100.0
1964	5.9	1.1	92.3	0.0	0.0	0.7	100.0
1965	6.4	1.3	84.0	0.0	0.0	8.3	100.0
1966	7.1	0.6	73.8	0.0	0.0	18.5	100.0
1967	8.4	0.6	77.7	0.0	0.0	13.3	100.0
1968	9.7	0.9	63.4	0.0	0.0	26.0	100.0
1969	11.2	0.7	66.7	0.0	0.0	21.4	100.0
1970	13.4	0.9	63.9	5.2	0.0	16.6	100.0
1971	18.2	0.9	55.5	9.4	0.0	16.0	100.0
1972	17.0	0.8	55.0	7.7	0.0	19.5	100.0
1973	17.5	0.4	47.0	6.1	0.0	29.0	100.0
1974	16.2	5.7	51.1	8.8	0.0	18.2	100.0
1975	14.2	8.0	42.5	10.3	0.0	25.0	100.0
1976	19.3	4.1	48.6	5.6	0.0	22.4	100.0
1977	17.8	2.9	48.3	2.9	0.0	28.1	100.0
1978	12.4	6.9	52.7	15.0	0.0	13.0	100.0
1979	12.9	25.4	40.2	13.4	0.0	8.4	100.0
1980	13.8	28.7	40.5	11.8	0.0	5.2	100.0
1981	9.3	24.0	33.2	10.3	0.0	23.2	100.0
1982	9.1	25.9	33.8	15.8	0.1	15.3	100.0
1983	14.2	27.5	33.9	16.0	0.2	8.2	100.0
1984	15.1	29.9	29.4	13.6	0.2	11.8	100.0
1985	14.8	23.1	22.5	13.6	0.3	25.7	100.0
1986	18.9	35.8	19.1	19.9	0.3	6.0	100.0
1987	13.0	36.2	15.9	7.3	0.1	27.5	100.0
1988	17.0	39.9	18.9	2.4	0.1	21.7	100.0

* *Excludes non-cash exchanges.*

Source: Energy, Mines and Resources Canada.

Table 6.10. Canadian energy trade, 1979-1988

	Oil	Natural gas	Coal	Electricity	Uranium	Total energy
			(millions of dollars)			
1979						
Exports	4 265	2 889	750	729	379	9 614
Imports	4 798	3	934	1	12	5 748
Balance	-533	2 886	-184	728	367	3 866
1980						
Exports	4 891	3 984	824	773	231	11 328
Imports	7 487	0	885	2	17	8 391
Balance	-2 596	3 984	-61	771	214	2 937
1981						
Exports	5 228	4 370	1 065	1 123	178	12 636
Imports	8 627	0	928	6	15	9 576
Balance	-3 399	4 370	137	1 117	163	3 060
1982						
Exports	5 218	4 755	1 203	1 120	359	13 089
Imports	5 763	1	1 017	5	17	6 793
Balance	-545	4 754	186	1 115	342	6 296
1983						
Exports	6 338	3 958	1 247	1 228	63	13 201
Imports	4 221	1	941	3	15	5 180
Balance	2 117	3 957	306	1 225	48	8 020
1984						
Exports	7 580	3 886	1 851	1 379	334	15 718
Imports	4 919	0	1 203	13	15	6 150
Balance	2 661	3 886	648	1 366	319	9 421
1985						
Exports	9 239	3 912	2 030	1 408	232	17 411
Imports	5 242	0	1 023	8	28	6 301
Balance	3 997	3 912	1 007	1 400	204	11 110
1986						
Exports	5 854	2 483	1 869	1 080	842	12 128
Imports	3 082	0	874	9	31	5 293
Balance	2 772	2 483	995	1 071	811	6 835
1987						
Exports	8 029	2 527	1 696	1 211	886	13 349
Imports	4 810	0	844	12	18	5 683
Balance	3 219	2 527	852	1 199	868	7 666
1988						
Exports	6 396	2 930	1 963	889	673	12 851
Imports	4 273	0	828	64	76	5 241
Balance	2 123	2 930	1 135	825	597	7 610

Source: Statistics Canada, ***Exports by Commodities*** *(65-004) and* ***Imports by Commodities*** *(65-007).*

Table 6.11. Annual Canadian interprovincial electricity trade, 1960-1988

Year	Total Canadian Generation (GW.h)	Delivered to other Provinces (GW.h) With Churchill Falls	Delivered to other Provinces (GW.h) Without Churchill Falls	Percentage of Interprovincial Transfers to Total Generation With Churchill Falls	Percentage of Interprovincial Transfers to Total Generation Without Churchill Falls
1960	114 378	7 108	7 108	6.2	6.2
1961	113 713	7 411	7 411	6.5	6.5
1962	117 469	7 188	7 188	6.1	6.1
1963	122 238	6 586	6 586	5.4	5.4
1964	134 987	8 241	8 241	6.1	6.1
1965	144 274	6 230	6 230	4.3	4.3
1966	158 135	7 771	7 771	4.9	4.9
1967	165 625	6 874	6 874	4.2	4.2
1968	176 378	6 578	6 578	3.7	3.7
1969	191 102	6 338	6 338	3.3	3.3
1970	204 723	8 137	8 137	4.0	4.0
1971	216 472	8 047	7 870	3.7	3.6
1972	240 213	17 787	11 470	7.4	4.8
1973	263 335	28 933	15 129	11.0	5.8
1974	279 915	40 768	18 624	14.6	6.7
1975	273 392	49 198	19 684	18.0	7.2
1976	294 043	51 931	19 909	17.7	6.8
1977	316 940	52 005	18 739	16.4	5.9
1978	335 946	53 645	16 706	16.0	5.0
1979	353 051	49 847	14 642	14.1	4.2
1980	367 306	52 709	14 965	14.4	4.1
1981	380 131	51 181	15 325	13.5	4.0
1982	376 805	50 303	14 609	13.4	3.9
1983	395 850	46 007	14 863	11.6	3.8
1984	425 414	53 302	17 375	12.5	4.1
1985	446 413	51 663	19 917	11.6	4.5
1986	455 795	50 706	20 102	11.1	4.4
1987	482 108	49 201	18 808	10.2	3.9
1988	489 044	41 517	10 790	8.5	2.2

Source: Energy, Mines and Resources Canada.

Table 6.12. Interprovincial electricity trade by destination, 1979-1988

	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
					(GW.h)					
Newfoundland to Quebec	35 290	37 829	35 941	35 779	31 229	36 012	31 836	30 695	30 393	30 727
Nova Scotia to New Brunswick	151	226	112	133	121	271	190	71	82	166
New Brunswick to Nova Scotia	494	172	303	217	737	303	360	620	659	186
New Brunswick to P.E.I.	362	392	481	478	520	550	585	610	483	486
New Brunswick to Quebec	0	0	0	0	1	0	2	0	20	309
Quebec to New Brunswick	3 588	3 675	3 717	3 615	3 971	4 342	5 951	7 204	6 840	2 690
Quebec to Ontario	5 389	5 567	6 494	5 768	5 378	7 364	8 685	7 292	5 942	2 289
Ontario to Quebec	204	50	58	57	52	68	106	17	15	43
Ontario to Manitoba	23	0	0	3	13	2	0	5	3	22
Manitoba to Ontario	1 827	1 575	1 164	1 066	955	940	959	735	1 050	538
Manitoba to Saskatchewan	1 248	1 579	1 305	1 488	1 610	1 593	1 530	1 211	1 262	1 370
Saskatchewan to Manitoba	774	951	1 054	1 066	1 209	1 299	1 240	1 076	1 220	1 109
Saskatchewan to Alberta	0	4	3	3	2	3	0	0	0	0
Alberta to Saskatchewan	0	0	0	0	4	0	0	0	0	0
Alberta to B.C.	394	385	261	188	46	259	182	617	710	1 218
B.C. to Alberta	103	100	165	442	163	296	37	553	521	364
Total	49 847	52 709	51 181	50 303	46 007	54 302	51 663	50 706	49 201	41 517

Source: Energy, Mines and Resources Canada.

7. TRANSMISSION

Total circuit length of electrical transmission in Canada, for lines rated at 50 kV and above, increased by 1123 km in 1988. The total length of Canadian bulk transmission is now 149 427 km. The largest share (32 per cent) is in the 100 kV to 149 kV range (Table 7.1).

To facilitate energy exchanges and enhance the reliability of electrical systems operation, there are now 35 major provincial interconnections, with a total design capability of about 10 000 MW (Table 7.2). One important interconnection under construction is a $41 million high-voltage-direct-current (HVDC) transmission line linking the electrical systems of Saskatchewan and Alberta. This interconnection will run from Swift Current, Saskatchewan, to Empress, Alberta, and will be the first Canadian link between the eastern and western power systems of North America.

There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 36 bulk power interties rated at 69 kV or higher, with a total power transfer capability of 17 500 MW (Table 7.3).

Canada is a world leader in long-distance electric power transmission, in both extra-high-voltage (EHV) alternating current and HVDC. A major influence on the development of Canada's expertise in these areas has been the country's abundant water power resources. Early in the century, pioneering efforts in high-voltage transmission resulted in the initial development of hydroelectric power at Niagara Falls, to supply the growing needs of communities in southern Ontario. In Quebec, the first 50-kV transmission lines were constructed to bring power from Shawinigan to Montreal.

After the harnessing of the major hydroelectric sites close to load centres, it became necessary to develop remote hydroelectric sources in several provinces and to integrate these sources into the power system over long-distance EHV and HVDC transmission lines. In 1965, Hydro-Québec installed the world's first 735-kV class transmission system. This system now extends over 1100 km from the Churchill Falls development in Labrador to Montreal; a comparable system of about the same distance extends from the James Bay development to Quebec's load centres.

In Manitoba, pioneering work was done to develop the $\pm$450-kV HVDC system, which now brings hydroelectric power from the Nelson River generating stations to customers in southern Manitoba. Ontario and British Columbia also have extensive EHV systems in the 500-kV class (Figure 7.1).

Such advances in Canadian transmission techniques have provided not only for long-distance bulk transmission, but also for extensive interconnections between neighbouring provinces and between Canada and the United States.

Table 7.1. Transmission circuit length in Canada, 1988

	50 - 99 kV	100 - 149 kV	150 - 199 kV	200 - 299 kV	300 - 399 kV	400 - 599 kV	600 kV and up	Total
				(km)				
Nfld.	2 230	1 906	-	2 005	-	-	612	6 753
P.E.I.	371	169	-	-	-	-	-	540
N.S.	2 026	1 676	-	1 067	96	-	-	4 865
N.B.	2 783	1 900	-	528	969	-	-	6 180
Que.	4 221	7 694	2 190	3 685	7 257	78	10 092	35 217
Ont.	247	12 312	-	13 666	6	2 411	-	28 642
Man.	6 651	4 256	-	4 157	-	2 042	-	17 106
Sask.	4 849	4 081	-	2 594	-	-	-	11 524
Alta.	3 440	8 748	159	5 802	-	356	-	18 505
B.C.	4 799	4 235	264	3 759	403	5 344	-	18 804
Yukon	64	497	-	-	-	-	-	561
N.W.T.	227	503	-	-	-	-	-	730
Canada	31 908 (21%)	47 977 (32%)	2 613 (2%)	37 263 (25%)	8 731 (6%)	10 231 (7%)	10 704 (7%)	149 427 (100%)

Source: Statistics Canada publication 57-202. Energy, Mines and Resources Canada.

Figure 7.1. Canada's major long-distance transmission systems, 1988

Table 7.2. Provincial interconnections at year end, 1988

Connection	Voltage	Design Capability*
	(kV)	(MW)
British Columbia - Alberta	1 x 500	800
	1 x 138	110
Saskatchewan - Manitoba	3 x 230	400
	2 x 110	100
Manitoba - Ontario	2 x 230	260
	1 x 115	
Ontario - Quebec	4 x 230	1 300
	7 x 120	
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x ±80(DC)	700
	2 x 345	
	2 x 230	300
New Brunswick - Nova Scotia	2 x 138	600
	1 x 345	
New Brunswick - P.E.I.	2 x 138	200

* *Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

Figure 7.2. Major provincial and international interconnections, 1988

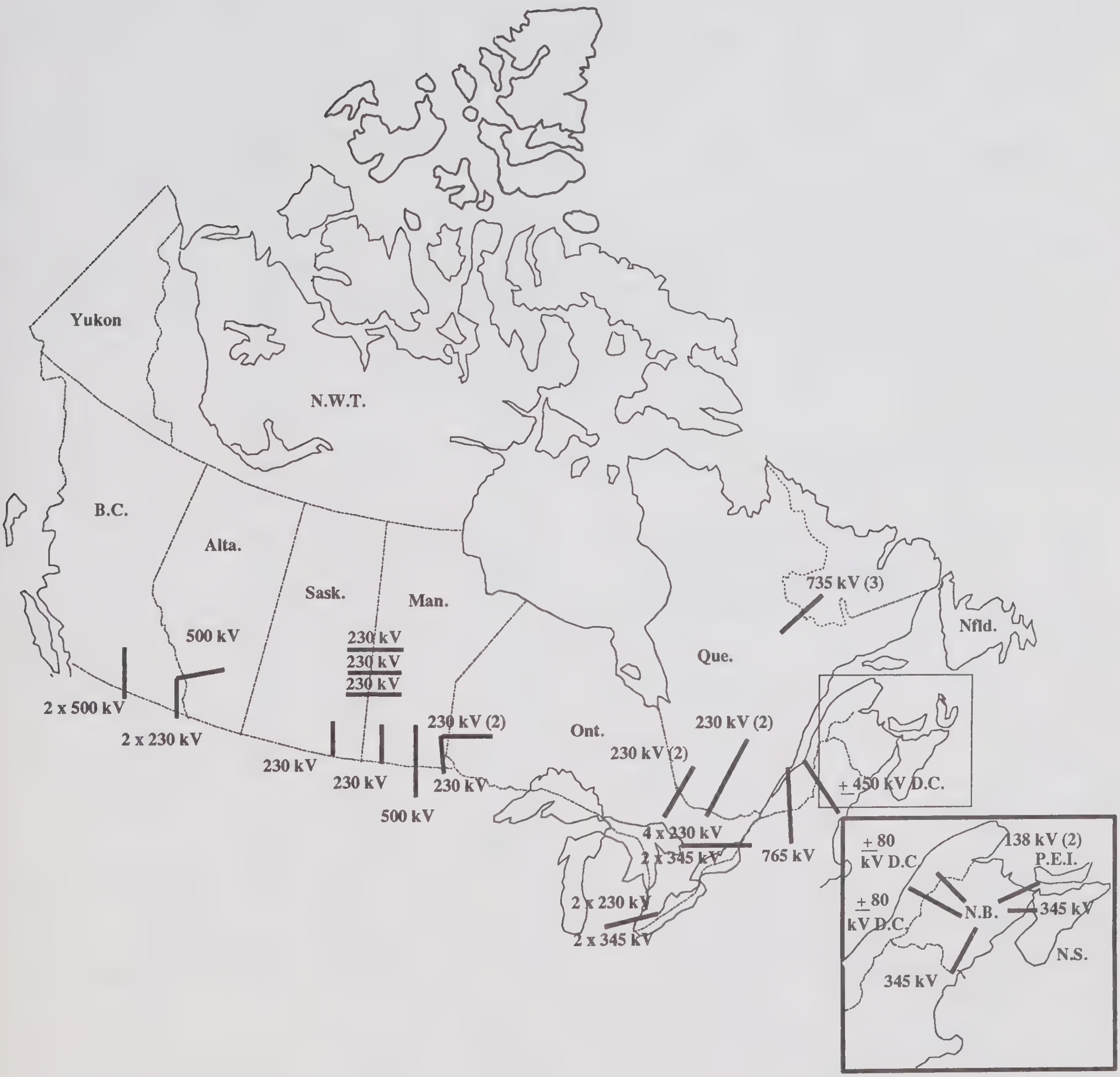


Table 7.3. Major interconnections between Canada and the United States*

Province	State	Voltage	Design Capability***
		(kV)	(MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	2 x 120	275
	New Hampshire	$\pm$ 450(DC)	690
Ontario**	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia**	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

* *35 MW capacity or over.*

** *The transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.*

*** *Actual transfer capability in practice will be different from design capability.*

Source: Energy, Mines and Resources Canada.

8. ELECTRIC UTILITY INVESTMENT AND FINANCING

The electric power industry is inherently capital-intensive. Between 1961 and 1987, the average capital-output ratio for the industry has been about 12.8, compared with 2.0 for the economy as a whole.

Due to stronger-than-expected domestic demand in the past two years, electric utilities increased their capital spending by more than $1 billion in 1988 over 1987 (Table 8.1). The latest survey of new plant and equipment spending indicates that Canada's electric utilities plan to raise outlays by 10 per cent in 1989 (Table 10.8).

The electric power industry continues to be the largest investment contributor in the Canadian energy sector (Table 8.2). Between 1971 and 1988, capital investment in generation accounted for about 57 per cent of total capital expenditures (Table 8.3). In 1988, Ontario Hydro and Hydro-Québec had the largest investment programs (Table 8.4).

Canada's electric utilities rely heavily on foreign financial markets to finance their capital investment. As of December 31, 1987, the total outstanding long-term debt of major electric utilities in Canada was $67 billion. Of this total, about 57 per cent (or $38 billion) was borrowed on the domestic market, and 43 per cent (or $29 billion) on international markets. Eighty-six per cent was raised in the United States; 7 per cent ($1.9 billion) in Switzerland; 4 per cent ($1.1 billion) in West Germany; 2 per cent ($0.7 billion) in Japan; and the remaining 1 per cent ($0.4 billion) in other European countries (Table 8.5).

In Canada and the United States, publicly owned electric utilities depend mainly on debt-financing. Investor-owned utilities, on the other hand, rely much more extensively on equity-financing (Table 8.6).

Table 8.1. Electric utility capital investment, 1971-1988

	Investment in electric power industry ($ million)	As a percentage of total energy investment	As a percentage of total investment in the economy	As a percentage of GDP
1971	1 747	52	8	1.8
1972	1 754	49	7	1.6
1973	2 244	53	8	1.8
1974	2 753	53	8	1.8
1975	3 957	58	9	2.3
1976	4 229	55	9	2.1
1977	4 884	56	10	2.2
1978	5 936	58	11	2.5
1979	6 364	53	10	2.3
1980	6 109	42	8	2.0
1981	7 319	40	9	2.1
1982	8 408	39	10	2.2
1983	7 770	42	10	1.9
1984	6 340	37	8	1.4
1985	5 729	34	6	1.2
1986	5 618	41	6	1.1
1987	6 233	47	5	1.1
1988	7 308	44	6	1.2

Source: Energy, Mines and Resources Canada.

Figure 8.1. Capital investment by function, 1988

Total Investment: $7.3 billion

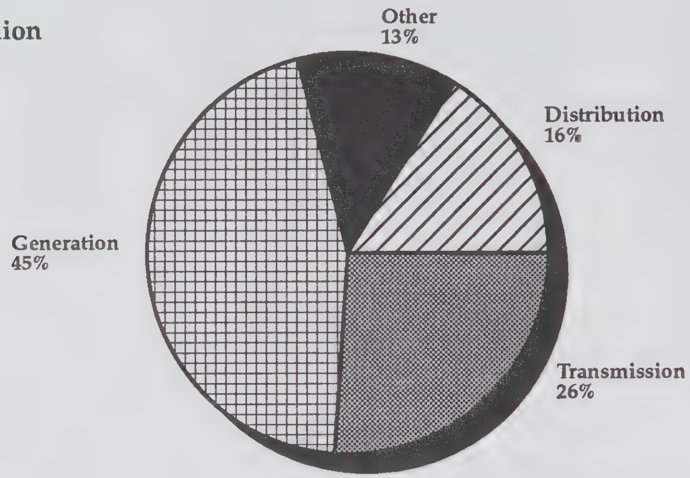


Table 8.2. Investment in energy-related industries, 1971-1988

Year	Crude oil and natural gas	Refined petroleum and coal products	Natural gas distribution	Electric power	Coal mines	Uranium mines	Other*	Total
				(millions of dollars)				
1971	463	231	115	1 747	90	6	702	3 381
1972	666	244	142	1 754	37	11	683	3 567
1973	824	319	146	2 244	39	18	589	4 220
1974	1 088	430	192	2 753	88	35	546	5 151
1975	1 390	450	193	3 957	121	30	662	6 831
1976	1 868	344	182	4 229	191	66	666	7 676
1977	2 251	367	213	4 884	248	113	666	8 782
1978	2 271	315	247	5 936	219	180	745	10 258
1979	3 886	274	263	6 364	214	243	793	12 037
1980	5 745	325	386	6 109	299	277	1 317	14 458
1981	6 445	848	409	7 319	576	289	2 285	18 419
1982	6 743	1 231	518	8 408	1 024	405	2 389	21 339
1983	6 564	841	577	7 770	1 225	413	1 190	18 715
1984	6 947	432	604	6 340	832	186	1 262	16 943
1985	8 184	336	604	5 729	471	160	1 101	16 925
1986	5 401	398	574	5 618	429	144	962	13 733
1987	4 331	660	534	6 233	355	106	1 168	13 348
1988	5 967	762	533	7 308	368	159	1 278	16 599

* *Natural gas processing plants, transportation, marketing, and oil and gas drilling contractors.*

Source: Energy, Mines and Resources Canada.

Table 8.3. Capital investment by function, 1971-1988

Year	Generation	Transmission	Distribution	Other	Total
			(millions of current dollars)		
1971	915	520	239	73	1 747
1972	1 020	432	229	73	1 754
1973	1 252	366	286	340	2 244
1974	1 805	388	422	138	2 753
1975	2 460	616	547	334	3 957
1976	2 576	794	464	395	4 229
1977	3 085	907	519	373	4 884
1978	3 499	1 290	499	648	5 936
1979	3 892	1 266	570	636	6 364
1980	3 580	1 114	703	712	6 109
1981	4 552	1 387	647	733	7 319
1982	5 026	1 436	937	1 009	8 408
1983	4 882	1 270	766	852	7 770
1984	3 530	1 158	834	818	6 340
1985	2 941	836	1 008	944	5 729
1986	3 214	815	989	600	5 618
1987	2 908	1 258	1 089	978	6 233
1988	3 289	1 900	1 169	950	7 308

Source: Energy, Mines and Resources Canada.

Table 8.4. Capital investment by major electric utility

	1987	1988	Year-over-year change
		(millions of current dollars)	
Newfoundland and Labrador Hydro	45	97	52
Newfoundland Light & Power	31	38	7
Maritime Electric Co. Ltd.	13	10	-3
Nova Scotia Power	101	217	116
NB Power	82	127	45
Hydro-Québec	1 688	2 107	419
Ontario Hydro	2 638	2 900	262
Manitoba Hydro	298	381	83
Saskatchewan Power	125	200	75
Alberta Power	133	124	-9
Edmonton Power	187	235	48
TransAlta Utilities	164	223	59
B.C. Hydro	142	238	96
Yukon Energy Corporation	1	3	2
Northwest Territories Power Corporation	8	27	19
Canada	5 656	6 927	1 271

Source: Energy, Mines and Resources Canada.

Table 8.5. Major electric utility long-term debt and sources of financing, 1987

	Long-Term Debt ($ millions)	Sources of Long-Term Debt Financing	
		Domestic (%)	Foreign (%)
Newfoundland and Labrador Hydro	1 425	52	48
Newfoundland Light & Power	141	93	7
Maritime Electric Co. Ltd.	18	100	0
Nova Scotia Power	1 372	74	26
NB Power	2 124	38	62
Hydro-Québec	22 102	41	59
Ontario Hydro	25 064	62	38
Manitoba Hydro	3 443	37	63
Saskatchewan Power	2 288	70	30
Alberta Power	480	100	0
Edmonton Power	722	100	0
TransAlta Utilities	1 084	95	5
B.C. Hydro	7 070	51	49
Northern Canada Power Commission	96	100	0
Canada	67 429	57	43

Source: Energy, Mines and Resources Canada.

Table 8.6. Comparison of Canadian and U.S. electric utility debt ratios, 1984 - 1987

	1984	1985	1986	1987
CANADA		(per cent)		
Publicly owned utilities				
Newfoundland and Labrador Hydro	91	90	88	86
Nova Scotia Power	94	95	96	98
NB Power	89	88	84	85
Hydro-Québec	75	76	76	75
Ontario Hydro	83	84	84	84
Manitoba Hydro	97	96	96	97
Winnipeg Hydro	67	68	71	72
Saskatchewan Power	86	87	88	87
Edmonton Power	84	80	75	75
B.C. Hydro	87	86	88	86
Northern Canada Power Commission	95	96	82	77
Investor-owned utilities				
Newfoundland Light & Power	44	45	43	48
Maritime Electric Co. Ltd.	48	43	42	43
TransAlta Utilities Corporation	33	33	38	35
Alberta Power	31	29	32	39
UNITED STATES				
Publicly owned utilities				
Tennessee Valley Authority	84	83	83	83
Bonneville Power Administration	100	100	100	100
Power Authority of the State of New York	69	71	72	74
Investor-owned utilities				
Boston Edison Company	50	51	46	48
Northeast Utilities	52	53	52	53
Consolidated Edison Company of New York	34	36	36	37
Niagara Mohawk Power Corporation	46	46	47	55
American Electric Power Company	54	53	53	54
Northern States Power Company	46	46	46	43
Washington Water Power Company	48	44	48	48
Pacific Gas and Electric Company	46	48	46	49

Source: Energy, Mines and Resources Canada.

9. COSTING AND PRICING

During the past 26 years, increases in the cost of building electric power stations have been relatively small, with the exception of the period 1973-1982 (Table 9.1).

Between 1973 and 1982, there were two key reasons for the rapid increases in the cost of electricity: the high rate of inflation, with an average increase of about 10 per cent; and the increased cost of fossil fuels, with an average annual increase of 18 per cent. High levels of inflation affect the electric utility industry by increasing the cost of constructing additional facilities and by increasing the cost of borrowed funds.

Table 9.1. Inflation, interest rates, and construction costs, 1960-1988

	Average Interest Rate	Increase in Construction Costs			
		Hydro	Steam	Nuclear	CPI
			(per cent)		
1960	5.7	-	-	-	-
1961	5.4	-	-	-	-
1962	5.4	2.8	-	-	1.2
1963	5.5	3.3	-	-	1.7
1964	5.5	3.2	-	-	1.8
1965	5.7	5.0	-	-	2.5
1966	6.4	6.2	-	-	3.7
1967	6.7	3.6	1.1	-	3.5
1968	7.8	4.2	2.8	-	4.7
1969	8.6	5.7	6.8	-	4.5
1970	9.3	6.6	7.4	-	3.3
1971	8.5	4.6	6.0	-	2.9
1972	8.4	6.3	6.1	6.9	4.8
1973	8.6	9.2	9.2	9.5	7.6
1974	10.2	18.8	20.5	19.2	10.9
1975	10.7	14.3	13.4	13.1	10.8
1976	10.4	8.9	10.0	9.7	7.5
1977	9.6	5.9	7.9	7.5	8.0
1978	10.0	7.7	8.7	8.0	9.0
1979	10.9	8.7	11.0	12.7	9.2
1980	13.3	10.0	11.6	22.0	10.2
1981	16.3	13.7	11.9	11.4	12.5
1982	15.9	7.2	6.8	5.3	10.8
1983	12.8	4.6	4.1	5.0	5.8
1984	12.5	3.2	2.8	0.1	4.4
1985	11.7	1.7	3.8	4.8	4.0
1986	10.5	4.1	3.5	3.5	4.1
1987	10.9	4.1	3.0	1.9	4.1
1988	11.0	4.0	5.7	2.8	4.0

Source: Interest rates - McLeod Young Weir Ltd.
Construction costs and CPI - Statistics Canada publications 62-007 and 62-001.

Fuel costs for electricity generation were generally stable until the oil crisis of 1973 (Table 9.2). The increases after 1973 were particularly significant for oil-fired generation. The cost of fuel generated from coal varies between regions of the country and depends on the type of coal used, its source, and the percentage of total energy supply derived from fossil-fuel plants.

In general, the cost of coal in western Canada has been substantially less than that in eastern Canada. The coal used for electricity generation in western Canada is produced domestically, while a large proportion of the coal used in eastern Canada is imported.

Electricity rates in Canada vary significantly from province to province (Table 9.3). In 1988, the weighted electricity-rate increase was 3.5 per cent, which is slightly less than the general inflation rate of 4.0 per cent, as measured by the Consumer Price Index (Table 9.6). Electricity prices in Canada continue to compare favourably with other industrialized countries.

Table 9.2. Cost of fuel for electricity generation, 1969-1987

	Eastern Coal*	Western Coal**	Petroleum	Natural Gas	Uranium	Total Fuels
			(mills/kW.h)			
1969	3.46	1.11	4.97	2.54	-	3.24
1970	3.60	1.38	5.68	2.47	-	3.25
1971	4.20	1.28	5.98	3.15	-	3.46
1972	4.32	1.34	6.41	3.93	-	3.42
1973	4.65	1.43	7.06	3.74	-	3.13
1974	5.38	1.54	11.36	5.18	-	4.10
1975	8.64	2.07	12.87	7.17	-	6.16
1976	11.43	2.97	15.38	11.74	1.14	8.11
1977	11.89	3.20	19.01	15.21	1.34	8.40
1978	13.12	2.88	21.22	16.19	1.61	8.82
1979	16.50	3.11	23.93	15.22	1.65	9.62
1980	18.22	3.75	26.22	15.47	2.65	10.69
1981	20.48	4.83	40.77	23.22	2.68	12.22
1982	22.61	5.76	44.88	30.16	2.87	14.04
1983	23.71	5.96	57.27	31.17	3.25	13.20
1984	24.85	5.94	65.11	34.15	3.84	13.64
1985	26.07	6.59	68.02	31.81	4.74	13.54
1986	25.88	5.13	45.15	27.11	4.52	10.70
1987	25.07	5.84	37.22	22.20	4.77	11.63

* *Nova Scotia, New Brunswick, and Ontario.*
** *Alberta, Saskatchewan, and Manitoba.*

Source: Calculated from ***Electric Power Statistics****, Statistics Canada, Catalogue 57-202, various issues.*

Table 9.3. Average revenue from electricity sales by province, 1978-1987

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987
					(current cents/kW.h)					
Nfld.	2.0	2.2	2.3	2.8	3.6	3.7	3.9	4.7	3.9	4.0
P.E.I.	6.4	7.2	8.1	10.0	12.0	12.3	12.8	12.9	11.5	10.3
N.S.	4.4	4.6	4.5	4.9	5.9	6.9	7.5	7.3	6.9	6.8
N.B.	3.2	3.7	4.1	4.8	5.1	5.4	5.5	5.8	5.5	5.5
Que.	1.7	2.0	2.2	2.6	3.1	3.4	3.4	3.5	3.4	3.4
Ont.	2.4	2.6	2.9	3.2	3.6	3.9	4.2	4.5	4.5	4.9
Man.	2.3	2.7	2.8	2.8	2.9	3.1	3.4	3.6	3.6	3.9
Sask.	2.7	2.7	2.9	3.6	4.0	4.2	4.5	4.8	5.0	5.5
Alta.	3.1	3.2	3.4	4.1	4.9	5.2	5.4	5.4	5.4	5.3
B.C.	2.2	2.4	2.6	3.0	3.8	3.8	4.1	4.4	4.2	4.2
Yukon	4.4	4.9	5.3	6.7	8.3	8.3	8.6	9.0	7.8	7.4
N.W.T.	7.7	9.0	10.0	11.5	14.8	17.9	16.7	16.3	15.9	17.6
Canada	2.3	2.5	2.8	3.1	3.7	3.9	4.1	4.3	4.2	4.4

Source: Statistics Canada publication 57-202.

Table 9.4. Major electric utilities' statements of income, 1987

	Total Revenue	O & M	Fuel Costs	Power Purchased	Depre - ciation	Taxes	Interest	Exchange Losses	Other Costs	Net Income
	(millions of current dollars)									
Newfoundland and Labrador Hydro	332	55	61	-	23	-	149	-	-	44
Newfoundland Light & Power	251	42	-	144	17	11	17	-	-	20
Maritime Electric Co. Ltd.	61	11	-	32	4	5	4	-	-	5
Nova Scotia Power	510	75	199	13	52	5	152	-	42	(28)
NB Power	867	92	175	132	82	-	259	-	91	36
Hydro-Québec	5 095	1 246	-	110	500	289	2 170	272	-	508
Ontario Hydro	5 280	1 150	1 124	117	723	90	1 702	126	(23)	271
Manitoba Hydro	580	240	-	35	80	26	250	3	-	(18)
Winnipeg Hydro	92	24	-	39	3	2	8	-	1	5
Saskatchewan Power	859	218	253	-	101	-	251	-	-	36
Alberta Power	409	22	131	-	49	82	70	-	-	55
Edmonton Power	280	44	-	77	18	22	5	-	48	66
TransAlta Utilities	925	185	-	21	144	245	129	-	22	179
B.C. Hydro	2 110	318	281	-	237	306	875	-	38	55
Northern Canada Power Commission	76	57	-	-	8	-	7	-	-	4
Canada	17 727	3 743	2 224	720	2 041	1 083	6 048	401	219	1 248

Source: Obtained from electric utilities' annual reports, 1987.

Table 9.5. Monthly electricity costs, January 1988 (Dollars)*

Sector:	**Residential**	**Commercial**	**Industrial**
Billing Demand (kW):	—	100	1000
Consumption (kW.h):	1000	25 000	400 000
St. John's	70.58	1 925.86	22 610.07
Charlottetown	101.70	3 284.55	37 937.55
Halifax	72.61	2 261.50	23 365.48
Moncton	64.50	2 006.30	20 450.00
Montreal	44.11	1 506.60	18 025.40
Ottawa	51.20	1 336.90	19 021.90
Toronto	59.90	1 820.25	22 104.00
Winnipeg	43.48	1 148.81	13 821.31
Regina	60.73	1 874.64	23 822.14
Calgary	50.12	1 437.09	16 593.47
Edmonton	51.54	1 565.15	20 002.24
Vancouver	53.32	1 332.85	16 071.30
Whitehorse	72.30	2 280.00	—
Yellowknife	103.53	2 762.50	40 692.50

* *Bills computed are on a net basis and exclude all taxes.*

Source: Statistics Canada publication 57-203.

Table 9.6. Average annual rate increases, 1979-1988

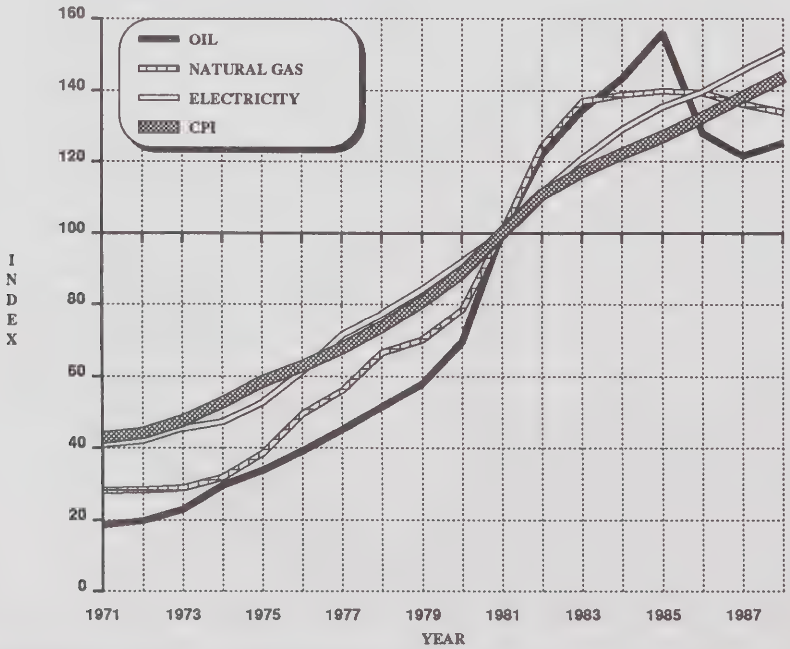
	Rate Changes (%): Average of all Customer Classes									
	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
Newfoundland and Labrador Hydro	-	19.0	15.8	-	18.2	-	-	-1.7	-	-
Newfoundland Light & Power	12.4	11.8	14.6	-	12.0	-	-	8.7	3.0	-1.1
Maritime Electric Co. Ltd.	-	13.1	21.4	-**	-**	-	3.7	-3.8	-	-1.3
Nova Scotia Power	12.5	-(b)	36.6	-	-	-	-	-	-	-
NB Power	7.9	7.8	9.8	-	8.8	6.2	4.6	-	-	-
Hydro-Québec	13.7	13.3	10.6	16.3	7.3	4.0	4.0	5.4	4.9	3.9
Ontario Hydro	7.7	7.3	10.0	10.0	8.2	7.5	8.6	4.0	5.0	4.7
Manitoba Hydro	14.4	-(a)	-	-	9.5	7.9	5.0	2.8	9.7	4.5
Saskatchewan Power	8.3	7.9	16.1	7.5	12.6	9.2	-	7.5	7.5	6.1
Edmonton Power	-	26.0	12.0	13.2	8.0	5.0	6.7	0	3.0	1.9
TransAlta Utilities	7.5	-	13.0	4.0	15.0	-	1.7	6.1	-1.8	-1.0
Alberta Power	-	12.3	28.9	-11.6*	2	-	-4.3	-8.6	-5.0	14.5
B.C. Hydro	5.5	7.6	2.6	20.0*	6.0	6.5	3.8	1.8	-	-

(a) *The provincial government froze rates from 1979 until 1983.*
(b) *The provincial government froze rates in 1980.*
* *Based on residential category.*
** *Does not reflect monthly changes to the cost of commodity and fuel adjustment charges.*

Source: Energy, Mines and Resources Canada.

Figure 9.1. Price indices, 1971-1988

1981 = 100



10. ELECTRICITY OUTLOOK

Forecasting electricity demand has become a difficult task in recent years. This is largely a result of the economic dislocation caused by rapidly rising energy prices, particularly between 1975-77 and 1980-82. The effects of higher energy prices have been felt globally, and adjustments have been made worldwide in the amount, types, and uses of energy. The collapse of world oil prices in 1986 has added to the uncertainty. Adjustments in energy-use patterns continue to make economic forecasting difficult, and this economic uncertainty, in turn, leads to uncertainty about future electricity demand.

Despite this uncertainty, forecasts of electricity demand are essential to ensure that sufficient generating capacity is available when it is needed. The long lead time in the construction of new generating facilities makes it necessary for utilities to calculate future demand many years in advance.

Based on the electric utilities' own projections, electricity demand for Canada as a whole is estimated to be 2.2 per cent during the period 1988-2005 (Table 10.1). The National Energy Board's forecast is 2.0 per cent for the same period, compared with the Department of Energy, Mines and Resources' forecast of 2.4 per cent (Figure 10.1). These forecasts are much lower than the historic average of 6 per cent for the 1947-1988 period.

The electric utilities project that peak demand will be about 2.3 per cent for the period 1988-2005 (Table 10.2). Since peak demand is expected to grow slightly faster than energy demand, the load factor for Canada as a whole is expected to decrease from 67.2 per cent in 1988 to 66.8 per cent by 2005 (tables 10.1 and 10.2). To meet the forecast growth in electricity demand, the electric utilities project net additions of generating capacity of 31 287 MW between 1988 and 2005, or

Table 10.1. Forecasts of domestic electricity demand

	1988	1990	1995	2000	2005	Average Annual Growth Rate 1988-2005
			(GW.h)			(%)
Nfld.	10 423	11 575	12 723	14 156	15 698	2.4
P.E.I.	704	747	822	883	950	1.8
N.S.	8 912	10 057	11 653	13 049	14 480	2.9
N.B.	12 646	13 757	15 987	17 934	19 857	2.7
Quebec	163 328	171 296	192 443	206 848	214 109	1.6
Ontario	140 677	144 288	161 662	175 463	191 529	1.8
Man.	16 867	17 996	20 072	22 029	23 889	2.1
Sask.	13 455	14 477	16 670	18 373	19 686	2.3
Alta.*	39 325	43 952	58 452	75 280	95 306	5.3
B.C.	54 078	57 065	62 840	68 595	74 872	1.9
Yukon	439	430	437	440	444	0.1
N.W.T.	466	496	501	507	512	0.6
Canada	461 320	486 136	554 262	613 557	671 332	2.2

* *Alberta Interconnected System provided high and low load-growth scenarios. The high-growth case is used.*

Source: Canadian electric utilities, and National Energy Board.

an average of 1840 MW per year (Table 10.3). Of the total net additions, hydro is expected to account for 64 per cent (20 021 MW); coal 14 per cent (4417 MW); nuclear 9 per cent (2391 MW); oil 3 per cent (974 MW); and other 2 per cent (549 MW) (Table 10.4).

Future electricity generation is still projected to be dominated by hydro. By the year 2005, the electric utilities project that hydro will account for 58 per cent of total electricity generation; coal 21 per cent; nuclear 16 per cent; natural gas 3 per cent; oil and other 1 per cent each (Table 10.6).

Between 1988 and 2005, the use of natural gas, coal and uranium for electricity generation is expected to increase, while the use of oil is expected to decline (Table 10.7).

Over the next ten years (1989-1998), major utilities in Canada are expected to invest about $115 billion. Of this total, investment in generation will account for 52 per cent ($60 billion); transmission 24 per cent ($27 billion); distribution 14 per cent ($16 billion); and other 10 per cent ($12 billion) (tables 10.8 and 10.9).

Electricity exports to the United States are expected to grow steadily to the year 2005 (Table 10.10)

Figure 10.1. Comparison of electricity demand forecasts

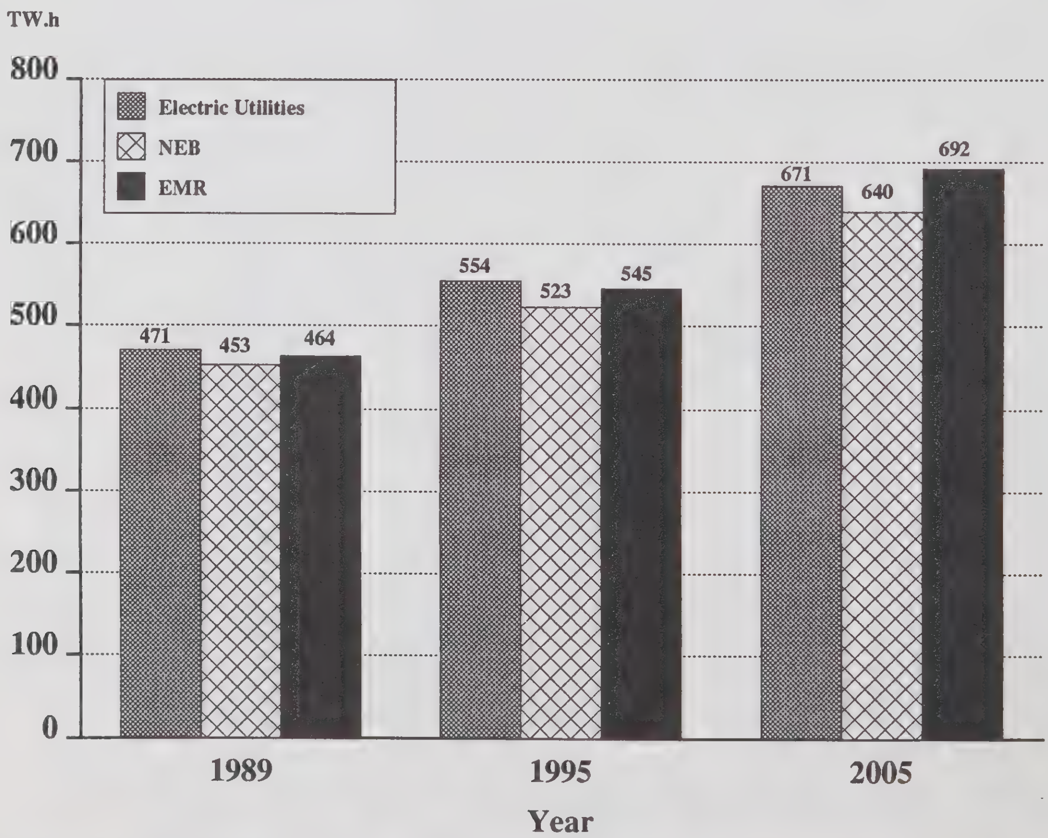


Table 10.2. Forecasts of domestic peak demand

	1988	1990	1995	2000	2005	Average Annual Growth Rate 1988-2005
			(MW)			(%)
Nfld.	1 740	1 844	2 046	2 338	2 586	2.4
P.E.I.	127	136	148	157	167	1.6
N.S.	1 706	1 919	2 243	2 549	2 849	3.1
N.B.	2 525	2 689	3 154	3 544	3 923	2.6
Quebec	28 688	28 374	33 084	37 832	42 571	2.3
Ontario	23 816	24 142	26 679	28 529	30 927	1.6
Man.	3 437	3 524	3 952	4 313	4 666	1.8
Sask.	2 280	2 519	2 904	3 199	3 439	2.5
Alta.	5 823	6 801	8 644	10 693	11 394	4.0
B.C.	8 054	8 914	9 904	10 904	12 019	2.4
Yukon	75	78	79	79	79	0.3
N.W.T.	111	115	117	120	121	0.5
Canada	78 382	81 055	92 954	104 257	114 741	2.3

Source: Canadian electric utilities, andNational Energy Board.

Table 10.3. Forecasts of installed generating capacity by province

	1988	1990	1995	2000	2005	Average Annual Growth Rate 1988-2005
			(MW)			(%)
Nfld.	7 426	7 373	8 243	8 252	8 311	0.7
P.E.I.	142	124	124	124	124	-0.8
N.S.	2 345	2 051	2 531	2 991	3 291	2.0
N.B.	3 471	3 480	4 180	4 630	4 630	1.7
Quebec	27 258	28 542	31 909	38 369	41 444	2.5
Ontario	32 955	32 685	34 080	35 111	35 171	0.4
Man.	4 125	4 332	5 321	5 707	6 357	2.6
Sask.	2 845	2 828	3 328	3 683	4 063	2.1
Alta.	7 600	7 759	9 260	11 622	13 941	3.6
B.C.	12 497	12 371	12 371	13 451	14 566	0.9
Yukon	145	149	159	179	184	1.4
N.W.T.	175	180	184	189	189	0.5
Canada	100 984	101 874	111 690	124 308	132 271	1.6

Source: Canadian electric utilities, and National Energy Board.

Figure 10.2. Comparison of generating capacity forecasts

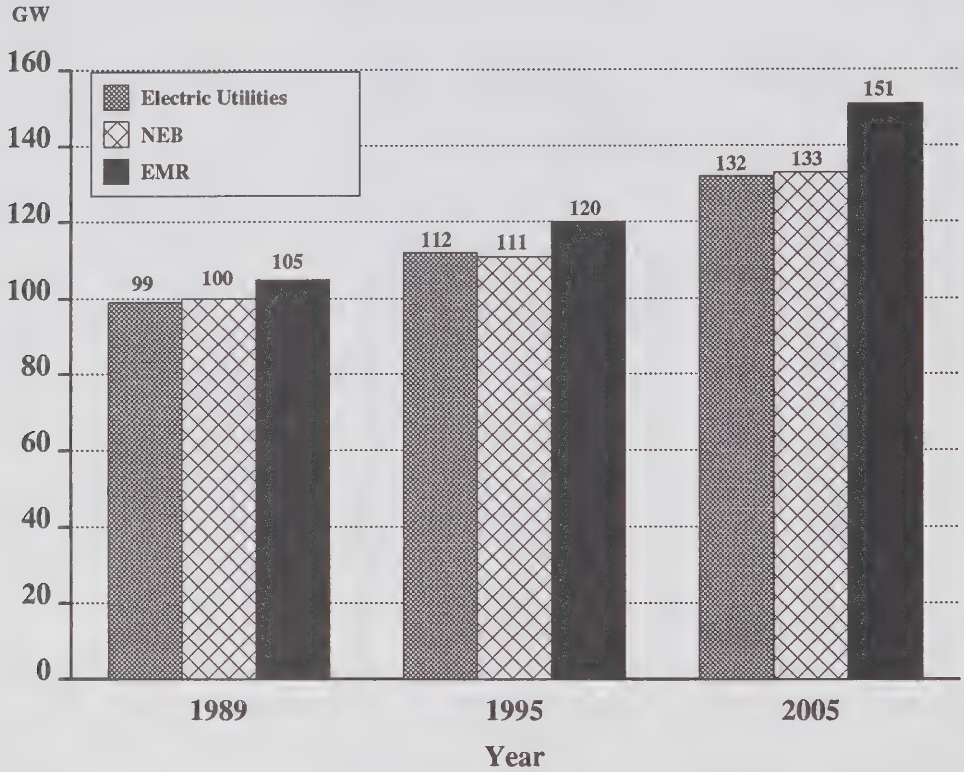


Table 10.4. Forecasts of installed generating capacity by fuel type in Canada

	1988	1990	1995	2000	2005
			(MW)		
Coal	19 183	18 852	20 218	22 201	23 600
Oil	7 311	7 224	8 029	8 223	8 285
Natural gas	3 782	3 776	3 827	5 067	6 177
Nuclear	12 586	12 874	15 517	15 517	15 517
Hydro	57 484*	58 568	63 187	72 225	77 505
Other	638	580	912	1 075	1 187
Total	100 984	101 874	111 690	124 308	132 271

* *Includes tidal power.*

Source: Canadian electric utilities, and National Energy Board.

Table 10.5. Utility forecasts of electricity generation by province

	1988	1990	1995	2000	2005	Average Annual Growth Rate 1988-2005
			(GW.h)			(%)
Nfld.	41 150	44 312	44 909	45 087	46 981	0.8
P.E.I.	218	225	225	225	225	0.2
N.S.	8 892	9 875	11 643	12 761	14 480	2.9
N.B.	15 772	15 196	20 131	22 552	24 023	2.5
Quebec	149 005	151 053	176 938	175 178	209 627	2.0
Ontario	142 743	147 846	165 610	166 476	191 904	1.8
Man.	16 308	22 688	28 999	32 290	33 630	4.3
Sask.	12 937	13 949	16 077	17 990	19 471	2.4
Alta.	40 172	43 948	58 452	71 264	95 312	5.2
B.C.	60 942	62 765	65 070	59 080	77 102	1.4
Yukon	439	455	505	558	617	2.0
N.W.T.	466	496	501	479	512	0.6
Canada	489 044	512 808	589 060	603 940	713 884	2.3

Source: Canadian electric utilities, and National Energy Board.

Figure 10.3. Comparison of electricity generation forecasts

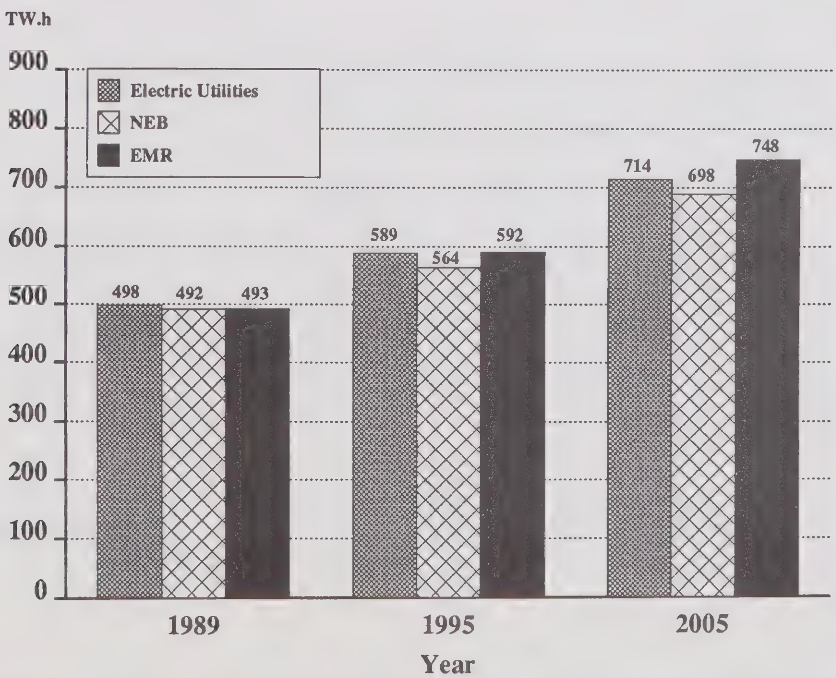


Table 10.6. Forecasts of electricity generation by fuel type in Canada

	1988	1990	1995	2000	2005
			(GW.h)		
Coal	86 192	78 622	88 177	117 359	146 677
Oil	10 982	12 705	9 397	6 779	9 446
Natural gas	8 045	8 653	14 216	11 091	23 556
Nuclear	78 176	87 975	114 579	110 352	114 579
Hydro	303 546	322 182	358 268	352 609	413 388
Other	2 103	2 671	4 423	5 750	6 238
Total	489 044	512 808	589 060	603 940	713 844

Source: Canadian electric utilities, and National Energy Board.

Table 10.7. Fuels required for electricity generation

	Coal (10^3 tonnes)	Oil (m^3)	Natural Gas ($10^6 m^3$)	Uranium (tonnes)
1988	47 270	2 491 752	3 628	1 358
1990	42 309	2 822 098	4 068	1 505
1995	48 924	1 888 962	5 874	1 956
2000	63 322	1 695 211	7 125	1 885
2005	77 116	1 867 864	8 473	1 955

Note: *1 m^3 oil = 6.3 bbls*
1 m^3 gas = 35.5 ft^3
1 tonne = 1000 kg

Source: Canadian electric utilities, and National Energy Board.

Table 10.8. Capital expenditures for major electric utilities, 1988-1998

	1988*	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
	(millions of current dollars)										
Nfld.	136	132	172	175	196	94	222	348	524	644	656
P.E.I.	10	12	20	11	10	10	12	13	10	10	19
N.S.	102	217	326	331	357	256	259	302	335	406	204
N.B.	163	243	390	620	494	294	186	330	449	292	183
Quebec	2 107	2 486	3 103	3 455	4 031	5 064	5 778	5 115	5 672	6 826	6 112
Ontario	2 900	3 500	3 100	2 600	2 300	2 500	3 300	4 000	3 600	4 000	5 000
Man.	381	477	511	436	408	299	403	549	904	1 123	1 265
Sask.	200	236	375	390	281	353	429	328	303	239	424
Alta	584	705	524	465	415	538	572	582	590	599	610
B.C.	260	354	323	382	334	531	635	809	1 147	1 653	1 627
Yukon	5	14	16	5	5	5	5	5	5	5	5
N.W.T.	27	14	24	36	24	12	9	9	9	9	9
Canada	6 875	8 391	8 884	8 906	8 855	9 956	11 810	12 390	13 548	15 806	16 113

** Actual data*

Source: Canadian electric utilities.

Table 10.9. Capital expenditures by function, 1988-1998

	1988*	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
	(millions of current dollars)										
Generation	3 299	4 226	4 526	4 460	4 409	5 120	6 002	6 682	7 549	8 265	8 257
Transmission	1 581	2 048	2 164	2 102	2 062	2 422	2 946	2 482	2 754	4 061	4 265
Distribution	1 251	1 225	1 326	1 397	1 509	1 555	1 663	1 768	1 736	1 812	1 887
Other	744	892	868	947	875	859	1 199	1 458	1 509	1 668	1 704
Total	6 875	8 391	8 884	8 906	8 855	9 956	11 810	12 390	13 548	15 806	16 113

** Actual data.*

Source: Canadian electric utilities.

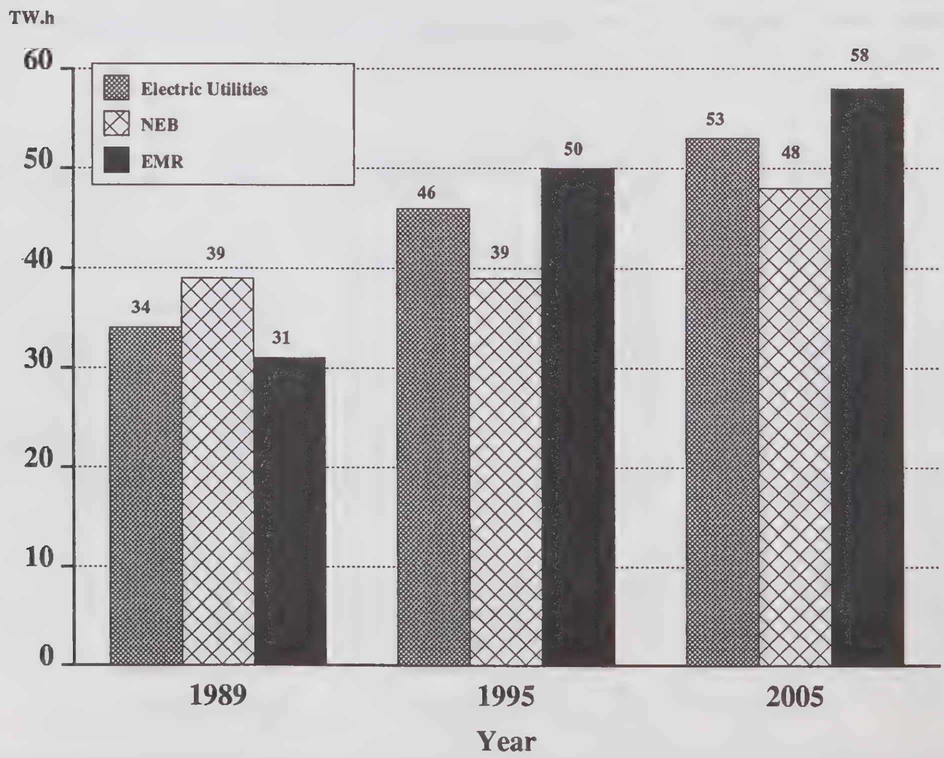
Table 10.10. Electricity exports to the United States

	1988*	1989	1990	1995	2000	2005
			(GW.h)			
New Brunswick	5 191	4 755	4 441	4 157	5 267	4 215
Quebec	11 863	12 267	11 822	16 059	23 341	26 289
Ontario	7 439	6 316	6 916	10 400	8 500	6 500
Manitoba	628	4 310	4 692	9 250	10 546	9 772
Saskatchewan	57	104	88	88	88	0
British Columbia	8 851	3 400	4 600	5 000	6 000	7 000
Canada	34 029	30 152	32 559	44 954	47 654	53 776

* *Actual data.*

Source : Canadian electric utilities.

Figure 10.4. Comparison of electricity export forecasts



APPENDIX A

Table A1. Installed capacity and electrical energy consumption in Canada, 1920-1988

Year	Installed Capacity: Thermal: Conventional	Installed Capacity: Thermal: Nuclear	Installed Capacity: Thermal: Sub-Total	Installed Capacity: Hydro	Installed Capacity: Total	Electrical Energy Consumption	Average Demand	Peak Demand	Reserve Margin	Reserve Margin	Load Factor
	(MW)					(GW.h) (a)	(MW) (b)	(MW) (c)	(MW)	(%) (d)	(%) (e)
1920	300	-	300	1 700	2 000	-	-	-	-	-	-
1930	400	-	400	4 300	4 700	19 468	2 222	-	-	-	-
1940	500	-	500	6 200	6 700	33 062	3 774	-	-	-	-
1950	900	-	900	8 900	9 800	55 037	6 283	-	-	-	-
1955	2 100	-	2 100	12 600	14 700	81 000	9 247	12 536	2 164	17	74
1960r	4 392	-	4 392	18 643	23 035	109 304	12 478	17 264	5 771	33	72
1965	7 557	20	7577	21 771	29 348	144 165	16 457	24 167	5 181	21	68
1970	14 287	240	14 527	28 298	42 826	202 337	23 098	34 592	8 234	24	67
1975	21 404	2 666	24 070	37 282	61 352	265 955	30 360	46 187	15 165	33	66
1976	23 039	3 466	26 505	39 488	65 993	284 829	32 515	49 527	16 456	33	66
1977	24 699	5 066	29 765	40 810	70 575	299 673	34 209	52 001	18 574	36	66
1978	26 154	5 866	32 020	41 898	73 918	316 435	36 123	54 106	19 812	37	67
1979	27 353	5 866	33 219	44 009	77 228	323 465	36 925	55 699	21 529	39	66
1980r	28 363	5 866	34 229	47 770	81 999	340 068	38 821	59 170	22 829	39	66
1981	28 493	5 600	34 093	49 216	83 308	346 333	39 536	59 237	24 071	41	67
1982	28 957	6 547	35 504	50 007	85 511	345 115	39 397	62 417	23 094	37	63
1983	30 447	7 771	38 218	51 274	89 492	359 838	41 077	66 866	22 626	34	61
1984	30 427	9 813	40 240	54 949	95 189	385 516	44 009	65 798	29 391	45	67
1985r	30 476	10 664	41 140	57 731	98 871	406 859	46 445	71 235	27 636	39	65
1986r	30 980	11 098	42 078	57 731	99 809	421 817	48 153	70 364	29 445	42	68
1987r	30 800	12 528	43 328	57 945	101 273	438 152	50 017	77 923	23 350	30	64
1988p	30 914	12 586	43 500	57 484	100 984	461 320	52 662	78 382	22 602	29	67

(a) 1920-55: Figures are approximate, computed using actual Statistics Canada data for stations generating energy from sale to which have been added estimates for stations generating entirely for own use. 1920-55: Canadian Energy Prospects (Royal Commission on Canada's Economic Prospects) John Davis, 1957. 1956-81: Statistics Canada Publication. 57-202.

(b) Average Demand = Energy Consumption ÷ 8 760 (hrs/yr).

(c) Statistics Canada Publication 57-204.

(d) Reserve margin = $\frac{\text{(Installed capacity - Peak demand)}}{\text{Peak demand}}$

(e) Load Factor = Average demand ÷ Peak demand.

p Preliminary figures. r Revised figures.

Source: Statistics Canada. Energy, Mines and Resources Canada.

Table A2. Installed and proposed generating capacity, 1988

	Hydro	Nuclear	Conventional Thermal	Total	% of Canadian Total
	(MW)				
Newfoundland	6 644	0	782	7 426	7.35
Prince Edward Island	0	0	122	122	.12
Nova Scotia	386	0	1 959	2 345	2.32
New Brunswick	903	680	1 908	3 491	3.46
Quebec	25 585	685	988	27 258	26.99
Ontario	7 775	11 221	13 959	32 955	32.63
Manitoba	3 641	0	484	4 125	4.08
Saskatchewan	832	0	2 013	2 845	2.82
Alberta	734	0	6 866	7 600	7.53
British Columbia	10 848	0	1 649	12 497	12.38
Yukon	83	0	41	124	.12
Northwest Territories	53	0	143	196	.19
Canada (Totals as of December 31, 1988)	57 484	12 586	30 914	100 984	100.00
Percentage of total	56.92	12.46	30.61	100.00	
Net additions during 1988	-461	58	114	-289	
Planned additions, 1989	1 056	881	485	2 422	

Source: Energy, Mines and Resources Canada.

Table A3. Conventional thermal capacity by principal fuel type* (MW)

	Steam					Gas Turbine			Internal Combustion			All Conventional Thermal				
	Coal	Oil	Gas	Other	Total	Oil	Gas	Total	Oil	Gas	Total	Coal	Oil	Gas	Other**	Total
Nfld.	0	530	0	0	530	170	0	170	82	0	82	0	782	0	0	782
P.E.I.	0	70	0	0	70	41	0	41	11	0	11	0	122	0	0	122
N.S.	1 182	553	0	19	1 754	205	0	205	1	0	1	1 182	759	0	19	1 960
N.B.	318	1 492	0	58	1 868	23	0	23	16	0	16	318	1 531	0	58	1 907
Que.	0	615	8	5	628	260	0	260	100	0	100	0	975	8	5	988
Ont.	10 872	2 200	186	63	13 321	447	181	628	4	6	10	10 872	2 651	373	63	13 959
Man.	419	0	4	23	446	24	0	24	14	0	14	419	38	4	23	484
Sask.	1 531	21	277	22	1 851	0	155	155	6	0	6	1 531	27	432	22	2 012
Alta.	4 861	0	1 318	118	6 297	0	524	524	15	30	45	4 861	15	1 872	118	6 866
B.C.	0	68	1 005	330	1 403	100	51	151	79	17	96	0	247	1 073	330	1 650
Yukon	0	0	0	0	0	0	20	20	44	0	44	0	44	20	0	64
N.W.T.	0	0	0	0	0	0	0	0	121	0	121	0	121	0	0	121
Canada	19 183	5 549	2 798	638	28 168	1 270	931	2 201	493	53	546	19 183	7 312	3 782	638	30 915

* *Preliminary figures as of December 31, 1988.*
** *Mainly wood wastes and black liquor.* *Numbers may not total due to rounding.*

Source: Electrical Energy Branch, Energy, Mines and Resources Canada.

Table A4. Electrical energy production by principal fuel type, 1988

	Conventional Thermal*							% of Total	% Generated By	
	Coal	Oil	Gas	Total	Nuclear	Hydro	Total	Generation	Utilities	Industry
	(GW.h)									
Newfoundland	0	1 419	0	1 419	0	39 731	41 150	8.41	98.75	1.25
Prince Edward Island	0	85	0	85	0	0	85	.02	100.00	.00
Nova Scotia	6 033	1 752	0	7 785	0	1 107	8 892	1.82	95.93	4.07
New Brunswick	1 865	6 188	0	7 983	5 342	2 580	15 905	3.25	95.32	4.68
Quebec	0	332	0	332	5 282	143 391	149 005	30.47	88.56	11.44
Ontario	35 033	510	1 334	36 877	67 552	38 314	142 743	29.19	97.21	2.79
Manitoba	924	0	5	929	0	15 379	16 308	3.33	99.72	.28
Saskatchewan	9 853	19	722	10 594	0	2 343	12 937	2.65	97.53	2.47
Alberta	33 627	120	4 994	38 741	0	1 431	40 172	8.21	91.95	8.05
British Columbia	0	420	1 949	2 369	0	58 573	60 942	12.46	80.60	19.40
Yukon	0	30	0	30	0	409	439	.09	100.00	.00
N.W.T.	0	177	1	178	0	288	466	.10	94.21	5.79
Canada	87 335	10 982	9 005	107 322	78 176	303 546	489 044	100.00	94.98	5.02

* *The conventional thermal breakdown is estimated.*

Source: Statistics Canada. Energy, Mines and Resources Canada.

Table A5. Provincial electricity imports and exports (GW.h)

Province	Year	Interprovincial Trade Exports	Interprovincial Trade Imports	Interprovincial Trade Net Exports	International Trade* Exports	International Trade* Imports	International Trade* Net Exports	Total Net Exports
Newfoundland	1988	30 727	-	30 727	-	-	-	30 727
	1987	30 393	-	30 393	-	-	-	30 393
	1986	30 695	-	30 695	-	-	-	30 695
	1985	31 837	-	31 837	-	-	-	31 837
	1984	36 043	-	36 043	-	-	-	36 043
Prince Edward Island	1988	-	486	-486	-	-	-	-486
	1987	-	483	-483	-	-	-	-483
	1986	-	610	-610	-	-	-	-610
	1985	-	575	-575	-	-	-	-575
	1984	-	539	-539	-	-	-	-539
Nova Scotia	1988	166	186	-20	-	-	-	-20
	1987	82	659	-577	-	-	-	-577
	1986	71	611	-540	-	-	-	-540
	1985	199	350	-151	-	-	-	-151
	1984	282	301	-19	-	-	-	-19
New Brunswick	1988	981	2 856	-1 875	5 191	190	5 001	3 126
	1987	1 164	6 922	-5 758	6 141	266	5 875	117
	1986	1 230	7 275	-6 045	7 008	424	6 584	539
	1985	927	6 026	-5 099	6 093	12	6 081	982
	1984	841	4 588	-3 747	5 657	17	5 640	1 893
Quebec	1988	4 979	31 079	-26 100	11 863	86	11 777	-14 323
	1987	12 782	30 427	-17 645	16 401	-	16 401	-1 244
	1986	14 496	30 712	-16 216	12 674	35	12 639	-3 577
	1985	14 491	31 878	-17 387	9 581	3	9 578	-7 809
	1984	11 668	36 105	-24 437	11 250	8	11 242	-13 195
Ontario	1988	65	2 827	-2 762	7 439	2 611	4 828	2 066
	1987	16	6 992	-6 976	8 497	2 113	6 384	-592
	1986	22	8 027	-8 005	7 957	1 693	6 264	-1 441
	1985	44	9 632	-9 588	10 563	1 701	8 862	-726
	1984	64	8 302	-8 238	11 370	913	10 457	2 219
Manitoba	1988	1 908	1 126	782	628	1 969	-1 341	-559
	1987	2 311	1 220	1 091	3 461	512	2 949	4 040
	1986	1 946	1 087	859	6 989	12	6 977	7 836
	1985	2 524	1 238	1 286	5 660	45	5 615	6 901
	1984	2 565	1 301	1 264	5 057	43	5 014	6 278
Saskatchewan	1988	1 109	1 369	-260	57	315	-258	-518
	1987	1 222	1 262	-40	113	84	29	-11
	1986	1 076	1 210	-134	151	64	87	-47
	1985	1 236	1 556	-320	163	93	70	-250
	1984	1 302	1 625	-323	86	66	20	-303

Table A5. Provincial electricity imports and exports (GW.h) (continued)

Province	Year	Interprovincial Trade			International Trade*			Total Net
		Exports	Imports	Net Exports	Exports	Imports	Net Exports	Exports
Alberta	1988	1 218	369	849	-	-	-	849
	1987	710	526	184	-	2	-2	182
	1986	617	555	62	-	3	-3	59
	1985	243	278	-35	-	2	-2	-37
	1984	262	302	-40	-	2	-2	-42
British Columbia	1988	364	1 219	-855	8 851	1 132	7 719	6 864
	1987	521	710	-189	12 815	493	12 322	12 133
	1986	553	617	-64	4 156	2 727	1 429	1 365
	1985	275	243	32	10 956	837	10 119	10 151
	1984	298	262	36	8 015	1 294	6 721	6 757
Yukon	1988	-	-	-	-	-	-	-
	1987	-	-	-	-	-	-	-
	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
	1984	-	-	-	-	-	-	-
Northwest Territories	1988	-	-	-	-	-	-	-
	1987	-	-	-	-	-	-	-
	1986	-	-	-	-	-	-	-
	1985	-	-	-	-	-	-	-
	1984	-	-	-	-	-	-	-
Canada	1988	-	-	-	34 029	6 305	27 724	27 724
	1987	-	-	-	47 428	3 470	43 958	43 958
	1986	-	-	-	38 934	4 957	33 977	33 977
	1985	-	-	-	43 016	2 693	40 323	40 323
	1984	-	-	-	41 436	2 343	39 093	39 093

* *Includes exchanges.*

Source: Statistics Canada.

Table A6. Canadian electricity exports by exporter and importer, 1988*

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
Fraser Inc.	Fraser Paper Ltd. (Maine)	19 477	380
Maine & New Brunswick Electrical Power Co. Ltd.	Maine Public Service Co. (Maine)	1 849	84
NB Power	Maine Public Service Co. (Maine)	6 085	175
NB Power	Eastern Maine Electric Cooperative Inc. (Maine)	3 815	68
NB Power	Maine Electric Power (Maine)	33 415	991
NB Power	Central Maine Power Co. (Maine)	38 375	1 163
NB Power	Bangor Hydro-Electric Co. (Maine)	7 128	229
NB Power	Massachusetts Municipal Wholesale Electric Co. (Massachusetts)	45 216	842
NB Power	Boston Edison Co. (Massachusetts)	50 778	863
NB Power	Commonwealth Electric Co. (Massachusetts)	12 419	210
NB Power	Public Service Co. of N.H. (New Hampshire)	4 030	43
NB Power	New England Elec. Power Co. (New England)	632	4
Hydro-Québec	Boston Edison Co. (Massachusetts)	9 167	214
Hydro-Québec	Montaup Electric Co. (Massachusetts)	2 765	64
Hydro-Québec	Citizens Utilities Co. (Vermont)	6 956	181
Hydro-Québec	Vermont Joint Owners (Vermont)	10 949	448
Hydro-Québec	Vermont Dep't of Public Service (Vermont)	47 434	1 157
Hydro-Québec	Vermont Marble Company (Vermont)	142	3
Hydro-Québec	New England Power Pool (New England)	11 407	3 931
Hydro-Québec	Niagara Mohawk Power Corp. (New York)	38 562	1 339
Hydro-Québec	New York Power Authority (New York)	118 249	4 525
Cornwall Electric	Niagara Mohawk Power Corp. (New York)	6 608	246
Canadian Niagara	Niagara Mohawk Power Corp. (New York)	10 984	396
Ontario Hydro	Vermont Dep't of Public Service (Vermont)	14 681	401
Ontario Hydro	Niagara Mohawk Power Corp. (New York)	116 734	3 853
Ontario Hydro	New York Power Authority (New York)	991	35
Ontario Hydro	New York Power Pool (New York)	10 203	304
Ontario Hydro	Detroit Edison Co. (Michigan)	10 248	382
Ontario Hydro	Minnesota Power & Light Co. (Minnesota)	170	4
Boise Cascade Canada Ltd.	Boise Cascade (Minnesota)	3	N
Manitoba Hydro	Northern States Power Co. (Minnesota)	17 309	605
Manitoba Hydro	Otter Tail Power Co. (Minnesota)	663	27
Manitoba Hydro	United Power Association (Minnesota)	40	1
Manitoba Hydro	Minnesota Power & Light Co. (Minnesota)	440	24
Manitoba Hydro	Minnkota Power Cooperative Inc. (North Dakota)	1 619	64
Saskatchewan Power Corporation	Basin Electric Power Cooperative (North Dakota)	27	1

Table A6. Canadian electricity exports by exporter and importer, 1988* (continued)

Exporter	Importer	Revenue ($000)	Quantity (GW.h)
Cominco Ltd.	Bonneville Power Administration (Washington)	787	36
Cominco Ltd.	Puget Sound Power & Light Co. (Washington)	1 342	68
Cominco Ltd.	Washington Water Power Co. (Washington)	339	19
Cominco Ltd.	Portland General Electric Co. (Oregon)	4 820	261
Cominco Ltd.	Pacific Power & Light Co. (Oregon)	62	4
Cominco Ltd.	Idaho Power Co. (Idaho)	841	46
Cominco Ltd.	Montana Power Co. (Montana)	37	2
Cominco Ltd.	Bonneville Power Administration (California)	1 436	69
Cominco Ltd.	Sierra Pacific Power Co. (Nevada)	384	20
Cominco Ltd.	Utah Power & Light Co. (Utah)	6	N
B.C. Hydro	Bonneville Power Administration (Washington)	10 481	467
B.C. Hydro	Puget Sound Power & Light Co. (Washington)	6 298	282
B.C. Hydro	Washington Water Power Co. (Washington)	4 454	162
B.C. Hydro	Seattle City Light (Washington)	771	32
B.C. Hydro	Portland General Electric Co. (Oregon)	37 230	2 717
B.C. Hydro	Pacific Power & Light Co. (Oregon)	293	15
B.C. Hydro	Idaho Power Co. (Idaho)	630	28
B.C. Hydro	Montana Power Co. (Montana)	79	3
B.C. Hydro	Bonneville Power Administration (California)	49 817	2 200
B.C. Hydro	Sierra Pacific Power Co. (Nevada)	452	21
B.C. Hydro	Utah Power & Light Co. (Utah)	185	8

N = negligible
** Excludes border accommodations.*

Source: Energy, Mines and Resources Canada.

Table A7. Generation capacity by type (MW)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEWFOUNDLAND							
Total end 1987	504.60	170.39	82.21	-	757.20	6 643.80	7 401.00
Changes 1988	25.00	-	-	-	25.00	-	25.00
Total end 1988	529.60	170.39	82.21	-	782.20	6 643.80	7 426.00
Additions proposed							
1989	25.00	-	-	-	25.00	-	25.00
1990	-	-	-	-	.00	-	.00
1991	-	108.00	-	-	108.00	-	108.00
1992	-	-	-	-	.00	31.00	31.00
2005	-	54.00	-	-	54.00	-	54.00
2007	-	54.00	-	-	54.00	-	54.00
2008	-	54.00	-	-	54.00	-	54.00
2010	-	54.00	-	-	54.00	-	54.00
Total end 2010	554.60	494.39	82.21	-	1 131.20	6 674.80	7 806.00
PRINCE EDWARD ISLAND							
Total end 1987	70.50	40.85	11.14	-	122.49	-	122.49
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	70.50	40.85	11.14	-	122.49	-	122.49
NOVA SCOTIA							
Total end 1987	1 753.79	205.00	0.60	-	1 959.39	386.36	2 345.75
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	1 753.79	205.00	0.60	-	1 959.39	386.36	2 345.75
Additions proposed							
1991	150.00	-	-	-	150.00	-	150.00
1993	150.00	-	-	-	150.00	-	150.00
1995	150.00	-	-	-	150.00	-	150.00
1997	150.00	-	-	-	150.00	-	150.00
1998	150.00	-	-	-	150.00	-	150.00
2000	150.00	-	-	-	150.00	-	150.00
Total end 2000	2 653.79	205.00	0.60	-	2 859.39	386.36	3 245.75

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
NEW BRUNSWICK							
Total end 1987	1 868.08	23.38	16.34	680.00	2 587.80	903.03	3 490.83
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	1 868.08	23.38	16.34	680.00	2 587.80	903.03	3 490.83
Additions proposed							
1989	25.00	30.00	-	-	55.00	-	55.00
1993	450.00	-	-	-	450.00	-	450.00
1994	200.00	-	-	-	200.00	-	200.00
1998	450.00	-	-	-	450.00	-	450.00
Total end 1998	2 993.08	53.38	16.34	680.00	3 742.80	903.03	4 645.83
QUEBEC							
Total end 1987	627.65	362.88	100.18	685.00	1 775.71	26 050.80	27 826.51
Changes 1988	-	-103.00	-	-	-103.00	-466.00	-569.00
Total end 1988	627.65	259.88	100.18	685.00	1 672.71	25 584.80	27 257.51
Additions proposed							
1989	-	-	-	-	.00	1 056.00	1 056.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	-	.00	950.00	950.00
1992	-	124.00	-	-	124.00	950.00	1 074.00
1993	-	372.00	-	-	372.00	-	372.00
1994	-	-	-	-	.00	700.00	700.00
1995	-	-	-	-	.00	1 517.00	1 517.00
1996	-	-	-	-	.00	699.00	699.00
1997	-	-	-	-	.00	614.00	614.00
1998	-	-	-	-	.00	2 009.00	2 009.00
1999	-	-	-	-	.00	1 244.00	1 244.00
2000	-	-	-	-	.00	680.00	680.00
2001	-	-	-	-	.00	330.00	330.00
2002	-	-	-	-	.00	110.00	110.00
2003	-	-	-	-	.00	424.00	424.00
2004	-	-	-	-	.00	775.00	775.00
2005	-	-	-	-	.00	249.00	249.00
2006	-	-	-	-	.00	621.00	621.00
Total end 2006	627.65	755.88	100.18	685.00	2 168.71	38 512.80	40 681.51

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ONTARIO							
Total end1987	13 183.15	575.93	9.52	11 163.00	24 931.60	7 770.80	32 702.40
Changes 1988	138.00	52.00	-	58.00	248.00	4.00	252.00
Total end 1988	13 321.15	627.93	9.52	11 221.00	25 179.60	7 774.80	32 954.40
Additions proposed							
1989	-	-	-	881.00	881.00	-	881.00
1990	-	-	-	-	.00	-	.00
1991	-	-	-	1 762.00	1 762.00	-	1 762.00
1992	-	-	-	881.00	881.00	-	881.00
Total end 1992	13 321.15	627.93	9.52	14 745.00	28 703.60	7 774.80	36 478.40
MANITOBA							
Total end 1987	445.80	23.80	14.16	-	483.76	3 641.10	4 124.86
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	445.80	23.80	14.16	-	483.76	3 641.10	4 124.86
Additions proposed							
1990	-	-	-	-	.00	256.00	256.00
1991	-	-	-	-	.00	640.00	640.00
1992	-	-	-	-	.00	384.00	384.00
1999	-	-	-	-	.00	260.00	260.00
2000	-	-	-	-	.00	390.00	390.00
2001	-	-	-	-	.00	650.00	650.00
2012	-	-	-	-	.00	87.50	87.50
2013	-	-	-	-	.00	262.50	262.50
Total end 2013	445.80	23.80	14.16	-	483.76	6 571.10	7 054.86
SASKATCHEWAN							
Total end 1987	1 851.76	154.92	6.60	-	2 013.28	832.56	2 845.84
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	1 851.76	154.92	6.60	-	2 013.28	832.56	2 845.84
Additions proposed							
1991	-	50.00	-	-	50.00	-	50.00
1992	300.00	-	-	-	300.00	-	300.00
1993	-	50.00	-	-	50.00	-	50.00
1994	-	-	-	-	.00	100.00	100.00
1995	-	50.00	-	-	50.00	-	50.00
Total end 1995	2 151.76	304.92	6.60	-	2 463.28	932.56	3 395.84

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
ALBERTA							
Total end 1987	6 297.42	524.10	44.87	-	6 866.39	733.70	7 600.09
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	6 297.42	524.10	44.87	-	6 866.39	733.70	7 600.09
Additions proposed							
1989	400.00	-	-	-	400.00	-	400.00
1990	380.00	-	-	-	380.00	-	380.00
1991	400.00	-	-	-	400.00	-	400.00
1994	-	400.00	-	-	400.00	-	400.00
1995	383.00	-	-	-	383.00	-	383.00
1996	383.00	-	-	-	383.00	-	383.00
1997	-	700.00	-	-	700.00	-	3 700.00
1998	360.00	100.00	-	-	460.00	-	460.00
1999	360.00	300.00	-	-	660.00	-	660.00
Total end 1999	8 963.42	2 024.10	44.87	-	11 032.39	733.70	11 766.09
BRITISH COLUMBIA							
Total end 1987	1 402.16	150.70	95.78	-	1 648.64	10 847.87	12 496.51
Changes 1988	-	-	-	-	.00	-	.00
Total end 1988	1 402.16	150.70	95.78	-	1 648.64	10 847.87	12 496.51
Additions proposed							
2000	-	-	-	-	.00	300.00	300.00
2001	-	-	-	-	.00	760.00	760.00
2002	-	-	-	-	.00	80.00	80.00
2003	-	-	-	-	.00	-	.00
2004	-	-	-	-	.00	110.00	110.00
2005	500.00	-	-	-	500.00	110.00	610.00
2006	500.00	-	-	-	500.00	55.00	555.00
2007	500.00	-	-	-	500.00	-	500.00
2008	500.00	-	-	-	500.00	-	500.00
Total end 2008	3 402.16	150.70	95.78	-	3 648.64	12 262.87	15 911.51
YUKON and N.W.T.							
Total end 1987	.00	19.50	162.24	-	181.74	135.10	316.84
Changes 1988	-	-	2.50	-	2.50	1.00	3.50
Total end 1988	.00	19.50	164.74	-	184.24	136.10	320.34

Table A7. Generation capacity by type (MW) (continued)

	Steam	Gas Turbine	Internal Combustion	Nuclear	Total Thermal	Hydro	Total
Additions proposed							
1989	-	-	4.60	-	4.60	-	4.60
1990	-	-	-	-	.00	.80	.80
1991	-	-	1.40	-	1.40	-	1.40
1992	-	-	.60	-	.60	-	.60
1993	-	-	5.20	-	5.20	-	5.20
1994	-	-	1.30	-	1.30	-	1.30
Total end 1994	.00	19.50	177.84	-	197.34	136.90	334.24
CANADA							
Total end 1987	28 004.91	2 251.45	543.64	12 528.00	43 328.00	57 945.12	101 273.12
Changes 1988	163.00	-51.00	2.50	58.00	172.50	-461.00	-288.50
Total end 1988	28 167.91	2 200.45	546.14	12 586.00	43 500.50	57 484.12	100 984.62
Additions proposed							
1989	450.00	30.00	4.60	881.00	1 365.60	1 056.00	2 421.60
1990	380.00	-	-	-	380.00	256.00	636.80
1991	550.00	158.00	1.40	1 762.00	2 471.40	1 590.00	4 061.40
1992	300.00	124.00	.60	881.00	1 305.60	1 365.00	2 670.60
1993	600.00	422.00	5.20	-	1 027.20	-	1 027.20
1994	200.00	400.00	1.30	-	601.30	800.00	1 401.30
1995	533.00	50.00	-	-	583.00	1 517.00	2 100.00
1996	383.00	-	-	-	383.00	699.00	1 082.00
1997	150.00	700.00	-	-	850.00	614.00	1 464.00
1998	960.00	100.00	-	-	1 060.00	2 009.00	3 069.00
1999	360.00	300.00	-	-	660.00	1 504.00	2 164.00
2000	150.00	-	-	-	150.00	1 370.00	1 520.00
2001	-	-	-	-	.00	1 740.00	1 740.00
2002	-	-	-	-	.00	190.00	190.00
2003	-	-	-	-	.00	424.00	424.00
2004	-	-	-	-	.00	885.00	885.00
2005	500.00	54.00	-	-	554.00	359.00	913.00
2006	500.00	-	-	-	500.00	676.00	1 176.00
2007	500.00	54.00	-	-	554.00	-	554.00
2008	500.00	54.00	-	-	554.00	-	554.00
2010	-	54.00	-	-	54.00	-	54.00
2012	-	-	-	-	.00	87.50	87.50
2013	-	-	-	-	.00	262.50	262.50
Total end 2013	**35 183.91**	**4 700.45**	**559.24**	**16 110.00**	**56 553.60**	**74 888.92**	**131 442.52**

Source: Energy, Mines and Resources Canada.

Table A8. Installed generating capacity expansion in Canada by station. Major 1988 additions and 1989 - 2013 projections

Province and Station	Type*	1988 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
NEWFOUNDLAND						
Holyrood[1]	S(o)	25	1988		I	
			1989	25	P	500
Stephenville	GT(o)		1991	54	P	108
Hardwoods	GT(o)		1991	54	P	108
Undecided	H		1992	31	P	31
Undecided	GT(o)		2005	54	P	
			2007	54	P	
			2008	54	P	
			2010	54	P	216
NOVA SCOTIA						
Point Aconi	S(c)		1993	150	P	
			1995	150	P	
			1997	150	P	450
New Site	S(c)		1998	150	P	
			2000	150	P	300
Trenton	S(c)		1991	150	C	360
NEW BRUNSWICK						
Belledune	S(c)		1993	450	P	
			1998	450	P	900
Grand Lake	S(c)		1994	200	P	285
Grand Manan	GT(o)		1989	30	C	30
Coleson Cove[1]	S(o)		1989	25	C	1 075
QUEBEC						
La Forge-1	H		1995	5 x 136	P	
			1995	137	P	817
La Forge-2	H		1996	3 x 90	P	270
Manic-1[1]	H		2003	134	P	318
Manic-2[1]	H		2003	290	P	1 305
Manic-3[1]	H		1997	2 x 285	P	1 753
Manic-5[1]	H		1994	44	P	1 468
			1995	44	P	
			1996	44	P	
			1997	44	P	
LG-1	H		1994	4 x 109	P	
			1994	2 x 110	P	

[1] *Uprating of exising units.*

Table A8. Installed generating capacity expansion in Canada by station. Major 1988 additions and 1989 - 2013 projections (continued)

Province and Station	Type*	1988 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
QUEBEC (continued)						
			1995	4 x 109	P	
			1995	2 x 110	P	1 312
LG-2A	H		1991	2 x 317	P	
			1991	316	P	
			1992	2 x 317	P	
			1992	316	P	7 228
Ste-Marguerite-3	H		1998	2 x 411	P	822
Grande Baleine-1	H		1998	2 x 396	P	
			1998	395	P	
			1999	396	P	
			1999	395	P	1 978
Grande Baleine-2	H		2000	154	P	
			2000	2 x 153	P	460
Grande Baleine-3	H		1999	3 x 151	P	453
Ashuapmushuan-3	H		2001	3 x 110	P	330
Ashuapmushuan-4	H		2000	2 x 110	P	
			2002	110	P	330
Eastmain-1	H		2004	3 x 170	P	510
Quenonisca	H		2004	5 x 53	P	265
Future peaking	GT(d)		1992	124	P	
			1993	372	P	496
ONTARIO						
Darlington	N		1989	881	C	
			1991	2 x 881	C	
			1992	881	C	
	GT	52	1989		I	3 628
MANITOBA						
Limestone	H		1990	2 x 128	C	
			1991	5 x 128	C	
			1992	3 x 128	C	1 280
Conawapa	H		1999	2 x 130	P	
			2000	3 x 130	P	
			2001	5 x 130	P	1 300
Wuskwatim	H		2012	87.5	P	
			2013	3 x 87.5	P	350

Table A8. Installed generating capacity expansion in Canada by station. Major 1988 additions and 1989 - 2013 projections (continued)

Province and Station	Type*	1988 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
SASKATCHEWAN						
Shand	S(c)		1992	300	C	300
Future peaking 1	GT(g)		1991	50	P	50
Future peaking 2	GT(g)		1993	50	P	50
Future peaking 3	GT(g)		1995	50	P	50
Future Hydro	H		1994	100	P	100
ALBERTA						
Genesee	S(c)		1989	400	C	
			1991	400	C	800
Sheerness	S(c)		1990	380	C	760
New Steam	S(c)		1995	383	P	
			1996	383	P	
			1998	360	P	
			1999	360	P	1 486
Peak Gas	GT		1994	4 x 100	P	
			1997	7 x 100	P	
			1998	100	P	
			1999	3 x 100	P	1 500
BRITISH COLUMBIA						
Keenleyside	H		2001	2 x 80	P	
			2002	80	P	240
Peace Site C	H		2000	2 x 150	P	
			2001	4 x 150	P	900
Murphy Creek	H		2004	2 x 55	P	
	H		2005	2 x 55	P	
			2006	55	P	275
Hat Creek	S(c)		2005	500	P	
			2006	500	P	
			2007	500	P	
			2008	500	P	2 000

Table A8. Installed generating capacity expansion in Canada by station. Major 1988 additions and 1989 - 2013 projections (continued)

Province and Station	Type*	1988 Additions	Completion Date	Additions Proposed	Status*	Plant Capacity
		(MW)		(MW)		(MW)
YUKON						
Dawson	IC		1993	1	P	4.4
McIntyre	H		1990	0.8	P	1.5
NORTHWEST TERRITORIES						
Various	IC	2.5	1989	4.6	P	
			1991	1.4	P	
			1992	0.6	P	
			1993	4.2	P	
			1994	1.3	P	

* Legend

H	Hydro	IC	Internal combustion
S(c)	Steam (coal)	GT	Gas turbine
N	Nuclear	I	Installed
P	Planned	C	Under construction
GT(o)	Gas turbine (oil)		
GT(g)	Gas turbine (natural gas)		
GT(d)	Gas turbine (diesel)		

Source: Energy, Mines and Resources Canada.

APPENDIX B

B1. Chronology of Canadian Electrical Energy Developments and Achievements

1846 Toronto, Hamilton, Niagara, and St. Catharines Electro-Magnetic Telegraph Company formed.

1847 Montreal Telegraph Company formed with lines from Quebec City to Toronto.

1858 Message sent from Queen Victoria to U.S. President Buchanan via first trans-Atlantic cable from Valentia, Ireland, to White Sands Bay, Newfoundland.

1873 Davis House in Winnipeg used arc light to illuminate front of building.

1876 Alexander Graham Bell made first long-distance telephone call from Paris, Ontario, to Brantford, Ontario, via battery power in Toronto - a total distance of 218 km.

1878 Robert McMicking began experiments with electric street lighting in Victoria.

1878 American Electric and Illuminating Company formed in Montreal--Canada's first electric light company.

1879 British Columbia Electric Railway launched.

1879 Electric light demonstrated in McConkey's Restaurant, Toronto.

1881 Toronto's first electric generator built by J.J. White. T. Eaton was the first customer.

1881 Ahearn & Soper of Ottawa introduced electric light for industry.

1882 One of North America's first hydroelectric generating facilities constructed at Chaudière Falls on the Ottawa River.

1882 F. Nicholls formed Toronto Electric Supply Company (forerunner of Canadian General Electric).

1883 Canada's first electric lighting plant started at Canadian Cottons, Cornwall, Ontario, by Thomas Edison.

1883 Toronto's first electric railway built by J.J. Wright.

1883 Canada's first street lights installed in Hamilton, Ontario.

1884 Canada's first electric utility set up in Pembroke, Ontario, by R.B. McAllister.

1884 Electric street lighting installed in Montreal and Toronto.

1885 First Canadian electric streetcar enters service in Toronto.

1885 St. John's Electric Light Company produced power for street and shop lighting.

1886 Victoria Electric Lighting Company (forerunner of B.C. Electric and B.C. Hydro) formed.

1887 Hydroelectric plant built at Twelve Mile Creek, near Welland, Ontario.

1887 Canadian engineer Sir Sandford Fleming completed Pacific cable.

1889 Calgary sawmill run by electricity; electric lights in Calgary, Brandon, and Winnipeg.

1890 Electric lights in Regina, Kenora, Portage la Prairie, and Moosejaw.

1891 Canadian Electrical Association formed.

1891 Edmonton Electric Light & Power Company begins operations.

1892 Canadian General Electric incorporated.

1892 Montreal's first hydroelectric plant established on the Lachine Canal.

1892 Canadian Niagara Power Company incorporated.

1892 Thomas L. "Carbide" Willson of Woodstock, Ontario, developed the electric-furnace process to manufacture calcium carbide.

1896 Marconi applied for a patent on wireless telegraphy.

1897 Hydroelectric power from Montmorency Falls supplies street lighting in Quebec City.

1897 Canadian branch of Westinghouse established at Hamilton.

1897 First long-distance, high-voltage transmission line (11 kV) carried power from St. Narcisse, to Trois-Rivières, Quebec - a distance of 29 km.

1898 Shawinigan Water & Power Company incorporated in Quebec.

1898 Royal Electric generated 15 MW at Chambly for transmission 26 km to Montreal.

1900 Hydroelectric power distributed in all provinces except Prince Edward Island and Saskatchewan.

1900 Montreal Light, Heat & Power Company formed.

1900 Canada's installed hydroelectric capacity reached 133 MW.

1901 Yukon Electrical Company Limited founded.

1901 Trans-Atlantic wireless demonstrated from Newfoundland by Marconi.

1902 Edmonton Electric Light & Power Company becomes a municipal utility.

1902 Shawinigan aluminium plant produced conductors for the Shawinigan-Montreal transmission line.

1903 Shawinigan Water & Power installed the world's largest generator (5,000 hp) and transmitted power over the world's longest and highest voltage line -136 km to Montreal at 50 kV.

1904 First significant exchange of power with the United States initiated at Niagara Falls.

1905 Ontario Hydro established.

1906 Hydroelectric power transmitted 96 km from the Winnipeg River to Winnipeg.

1910 Canada's installed hydroelectric capacity reached 700 MW.

1910 First 110-kV transmission line built from Niagara Falls to Dundas, Ontario.

1910 Quebec Streams Commission established.

1911 Calgary Power Co. Ltd. registered on March 17.

1918 New Brunswick Electric Power Commission created.

1918 Maritime Electric Company established.

1919 Ernest Rutherford of McGill University achieved atomic fission.

1919 Manitoba Power Commission established.

1919 Nova Scotia Power Commission established.

1921 Sir Adam Beck No.1 generating plant opened in Niagara Falls, then the largest in the world. Total capacity installed by 1924 was 528 MW.

1924 Newfoundland Light & Power Company established.

1928 World's first 10 000 kW, 3 600 rpm steam-driven turbo generator installed at Edmonton Power's Rossdale generating station.

1929 Saskatchewan Power Commission formed.

1930 Canada's installed generating capacity reached 4700 MW.

1940 The Canadian Standards Association assumed responsibility for approvals testing of electrical equipment.

1944 Hydro-Québec formed; acquired the facilities of the Montreal Light, Heat and Power Company.

1948 Northern Canada Power Commission created.

1949 Manitoba Hydro-Electric Board established.

1951 First 100-MW thermal generating unit installed.

1954 Newfoundland and Labrador Hydro created.

1956 First 315-kV transmission lines energized to carry power from Bersimis No.1 in northeastern Quebec to Quebec City and Montreal.

1956 First tie-line between Manitoba and Ontario enters service for the interchange of power. The Seven Sisters-Kenora transmission line connected the northwestern system of Ontario Hydro and the southern system of Manitoba Hydro.

1957 Edmonton Power is the first Canadian utility to utilize a high-voltage (72 kV) high-pressure oil-filled pipe cable system.

1957 First Canadian pumping/generating station (capacity 177 MW) enters service at Niagara Falls.

1958 Great Lakes Power Company installed highest head (34 m) variable pitch blade Kaplan turbine in North America.

1960 Beauharnois (Quebec) first generating station to exceed 1000 MW installed. By 1986, installed capacity at this station reached 1639 MW.

1961 Largest single generating unit in Canada (300 MW) begins producing electricity at Ontario Hydro's Lakeview generating station.

1962 Saskatchewan Power installed first 25-kV underground residential distribution system.

1962 B.C. Hydro acquired the B.C. Electric Company.

1963 Hydro-Québec acquired private power companies, including Shawinigan Water & Power.

1963 Ratification of the Columbia River Treaty by Canada and the U.S. allowed B.C. Hydro to proceed with the construction of the Duncan, Keenleyside and Mica dams.

1965 First 735-kV transmission line from Manicouagan-Outardes to the Quebec load centres energized. At the time, it was the highest A.C. voltage in commercial use in the world.

1966 Development of the hydroelectric potential of the Nelson River in northern Manitoba begins.

1967 First commercial-scale (220 MW) CANDU nuclear generating station in service at Douglas Point, Ontario.

1967 Ontario Hydro completes a 696-km, 500-kV transmission line from the Mattagami - Abitibi complex to Toronto.

1968 Power from Peace River transmitted to the B.C. lower mainland via a 918-km, 500-kV line.

1968 First Canadian DC transmission in service between Vancouver Island and the mainland at 260 kV.

1969 First 500-MW thermal generating unit operating at Lambton, Ontario.

1971 First two of four 542-MW nuclear generating units commissioned at Pickering, Ontario.

1971 First two units (500 MW and 475 MW) of the Churchill Falls, Labrador, hydroelectric station commissioned.

1971 Alberta Power established as the operating company for all of Canadian Utilities Limited's electric operations.

1972 World's largest solid-state high-voltage, direct- current (HVDC) converter/inverter terminal (320 MW) placed in service at Eel River, New Brunswick.

1972 An 880-km, 450-kV HVDC long-distance transmission system placed in commercial operation from the Nelson River to Winnipeg.

1973 Nova Scotia Power Commission became Nova Scotia Power Corporation, incorporating Nova Scotia Light & Power Company.

1974 Completion of the Churchill Falls generating station, with a total capacity of 5429 MW.

1974 Kettle hydro generating station, Manitoba Hydro's first generating station to be developed on the lower Nelson River, completed with a total capacity of 1272 MW.

1976 First 825-MW unit of the Bruce nuclear generating complex commissioned. (Total capacity of the complex is now 6600 MW.)

1978 New Brunswick-P.E.I. 100-MW submarine cable interconnection placed in service.

1979 First four 333-MW units of the LG 2 (James Bay) hydroelectric station placed in service by Hydro-Québec. (Total station capacity is 5328 MW, achieved by 1981.)

1983 A process to remove low-level PCBs from mineral oil is developed by Ontario Hydro.

1983 Point Lepreau No.1 nuclear power unit (680 MW) placed in service by N.B. Power at Point Lepreau, New Brunswick.

1984 First tidal power generating plant in North America placed in service by Nova Scotia Power at Annapolis Royal, Nova Scotia.

1986 TransAlta Utilities and B.C. Hydro commission 500-kV interconnection.

1986 The last unit (Unit 8) of Ontario Hydro's Pickering B nuclear station declared in service.

1987 Formation of the Yukon Energy Corporation.

1988 SaskPower completes the Athabasca transmission line, the longest line in its system. The 115-kV line stretches 355 km from near Uranium City to Rabbit Lake.

1988 Formation of the Northwest Territories Power Corporation.

B2. Chronology of Regional Interconnections

Interconnection	Voltage (kV)	Date-in-Service
Quebec-Ontario	230	1928
Quebec-Ontario	115	1930 (1)
Quebec-Ontario	230	1932
Quebec-Ontario	115	1933 (1))
Quebec-Ontario	115	1940 (1)
Quebec-Ontario	230	1941
Quebec-Ontario	115	1942
Quebec-Ontario	115	1949
Quebec-Ontario	115	1949
Manitoba-Ontario	115	1956 (2)
Manitoba-Saskatchewan	230	1960 (3)
New Brunswick-Nova Scotia	138	1961
New Brunswick-Nova Scotia	138	1965
Quebec-New Brunswick	69	1965
Quebec-Ontario	115	1966
Quebec-Ontario	115	1966
Western Ontario-Eastern Ontario	230	1969
Labrador-Quebec	735	1971
Labrador-Quebec	735	1972
Western Ontario-Eastern Ontario	230	1972
Manitoba-Saskatchewan	230	1972
Manitoba-Saskatchewan	110	1981 (6)
Manitoba-Saskatchewan	110	1981 (6)
Manitoba-Ontario	230	1972
Quebec-New Brunswick	$\pm$80 (DC)	1972
Quebec-New Brunswick	230	1972
Manitoba-Ontario	230	1973
Labrador-Quebec	735	1973
Alberta-British Columbia	138	1973
New Brunswick-Nova Scotia	345	1976 (4)
New Brunswick-Prince Edward Island	138	1977 (5)
New Brunswick-Prince Edward Island	138	1977 (5)
Manitoba-Saskatchewan	230	1979
Manitoba-Saskatchewan	110	1981 (6)
Manitoba-Saskatchewan	110	1981 (6)
Alberta-British Columbia	500	1985
Quebec-New Brunswick	$\pm$80 (DC)	1985
Quebec-New Brunswick	345	1985

Notes: (1) *230 kV construction.* (2) *Constructed in 1931; interconnected in 1956.* (3) *Operated at 138 kV unit 1968.* (4) *Operated at 138 kV until 1979.* (5) *Submarine cable.* (6) *Constructed in 1930. Purchased by SaskPower from Churchill River Power Company in 1981.*

All interconnections are alternating current (AC), except for the Quebec-New Brunswick direct current (DC) facilities. All Quebec-Ontario interconnections and both Quebec-New Brunswick AC interconnections are radial (i.e. between one system and an isolated section of the other system).

APPENDIX C

Remaining Hydroelectric Potential in Canada*

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
NEWFOUNDLAND				
Gull Island	1698	1698	1698	76
Muskrat Falls	618	618	618	87
Lobstick	160	160	-	71
Pinware	77	77	-	67
Alexis	98	98	-	72
Paradise (Lab.)	89	89	-	66
Minipi	255	255	-	76
Fig	204	204	-	77
Eagle River	661	661	-	71
Naskaupi	290	290	-	73
Kaniriktok	394	394	-	75
Granite Canal	31	31	31	80
Island Pond	30	30	30	70
Round Pond	18	18	18	84
Sub Total	**4623**	**4623**	**2395**	
OTHER SITES				
10 MW	186	-	-	61
<10 MW	392	-	-	61
TOTAL ALL SITES	**5201**	**4623**	**2395**	
NOVA SCOTIA				
10 MW	75	75	-	28
<10 MW	15	15	-	54
Sub Total	**90**	**90**	-	
TIDAL				
Cumberland Basin	1428	1428	-	26
Minas Basin	5338	5338	-	31
Shepody Bay	1643	1643	-	25
TOTAL ALL SITES	**8499**	**8499**	-	
NEW BRUNSWICK				
Grand Falls (Ext)	300	300	300	21
Morrill	140	140	140	35
Green River	160	160	-	7
Other sites	340	-	-	61
TOTAL ALL SITES	**940**	**600**	**440**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
QUEBEC				
LG-1	1 312	1 312	1 312	64
Laforge-1	817	817	817	59
Brisay	382	382	382	68
Eastmain-1	510	510	510	63
Eastmain-2	200	200	-	74
Ste-Marguerite	822	822	822	58
Grande Baleine	2 891	2 891	2 891	60
Ashuapmushuan	776	550	550	75
NBR	8 700	8 700	8 700	61
Nastapoca	768	768	-	59
Sakami	187	187	-	79
La Romaine	1 710	1 710	1 710	59
Laforge-2	270	270	270	72
Haut St-Maurice	700	700	-	64
Matawin	212	212	-	75
Outaouais Sup.	281	281	-	45
Rapide-Manigance	78	78	-	88
Temiscamingue	195	195	-	53
Toulnoustouc	71	71	-	48
Aguanus	329	329	-	79
Magpie	354	354	-	79
Moisie	1 014	1 014	-	79
Musquaro	86	86	-	78
Natashquan	703	703	-	79
Olomane	300	300	-	80
Petit-Mecatina	1 754	1 754	-	59
St-Augustin	66	66	-	59
St-Paul	157	157	-	53
A-la-Baleine	807	807	-	78
Arnaud-Payne	592	592	-	67
Aux-Feuilles	711	711	-	80
Caniapiscau	2 240	2 240	-	81
Eau-Claire	321	321	-	60
George	2 826	2 826	-	80
Harricana	1 032	1 032	-	80
Archipel	418	418	-	93
Other Ident. Sites	5 200	5 200	-	61
OTHER SITES	4 800	-	-	61
Sub total	**44 592**	**39 566**	**17 964**	
TIDAL	26 416	-	-	25
TOTAL ALL SITES	**71 008**	**39 566**	**17 964**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ONTARIO				
Long Sault Rapids	52	52	52	52
Abitibi Canyon (Ext)	463	463	463	3
Newpost Creek	26	26	-	76
Otter Rapids (Ext)	174	174	174	3
Nine Mile Rapids	295	295	295	28
Sand Rapids	131	131	-	31
Allan Rapids	131	131	-	31
Ear Falls (Ext)	15	15	15	37
Maynard Falls	51	51	51	52
Little Jackfish	132	132	132	49
Highland Falls	94	94	-	18
Farm Rapids	13	13	-	52
Coral Rapids	192	192	-	19
Blacksmith Rapids	140	140	-	30
Upper Ten Mile Rapids	16	16	-	67
Yellow Falls	54	54	54	26
Cypress Falls	42	42	42	29
Little Long (Ext)	61	61	61	13
Smoky Falls (Redev)	182	182	182	32
Harmon (Ext)	68	68	68	16
Kipling (Ext)	68	68	68	16
Grand Rapids	174	174	174	41
Thunderhouse Falls	42	42	-	48
Long Rapids	126	126	-	44
Mileage 66	81	81	-	40
Mileage 25	80	80	-	40
Patten Post	250	250	250	17
Ragged Chute (Redev)	98	98	98	21
Grey Goose	140	140	140	48
Renison	135	135	135	47
Adam Beck (Ext)	550	550	550	30
Paquette Rapids	29	29	-	89
Manitou Falls	58	58	-	17
Marathon	65	65	-	18
Spanish Site 4	80	80	-	38
Spanish Site 1	40	40	-	38

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ONTARIO (continued)				
Denison Falls	36	36	-	29
Chicagouse Falls	28	28	-	38
Lower Ten Mile Rapids	19	19	-	67
Umbata Falls	51	51	-	40
Chigamiwingum Falls	57	57	-	41
Matabitchuan (Redev)	73	73	-	12
Alexander (Ext)	19	19	-	11
Cameron (Ext)	18	18	-	11
Pine Portage (Ext)	28	28	-	4
Chat Falls (Ext)	20	20	-	23
Chenaux (Ext)	196	196	-	5
Des Joachims (Ext)	348	348	-	5
Otto Holden (Ext)	203	203	-	3
Chaudière Falls (Redev)	72	72	-	66
Lake Temiscaming	24	24	-	73
Sub total	**5 540**	**5 540**	**3 004**	
OTHER SITES				
>10 MW	5 480	5 480	360	53
< 10 MW	1 365	1 365	660	66
TOTAL ALL SITES	**12 385**	**12 385**	**4 024**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
MANITOBA				
Conawapa	1 240	1 240	1 240	64
Gillam Island	1 000	1 000	1 000	65
Gull	650	650	650	64
Birthday	450	450	450	69
Red Rock	220	220	220	67
Whitemud	280	280	280	61
Granville Falls	150	150	150	61
First Rapids	190	190	190	78
Manasan	260	260	260	70
Wuskwatim	330	330	330	69
Notigi	100	100	100	68
Kelsey (Ext)	220	220	220	26
Sub total	**5090**	**5090**	**5090**	
OTHER SITES				
>10 MW	3000	-	-	61
< 10 MW	100	-	-	61
TOTAL ALL SITES	**8190**	**5090**	**5090**	
SASKATCHEWAN				
Island Falls (Ext)	100	100	35	70
Wintego	285	285	285	60
Choiceland	150	150	150	40
Forks	400	400	400	40
Sub total	**935**	**935**	**870**	
OTHER SITES	1254	-	-	60
TOTAL ALL SITES	**2189**	**935**	**870**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ALBERTA				
Berland	71	71	-	61
McLeod	36	36	-	61
McLeod Valley	22	22	-	61
Pembina	12	12	-	61
Cardinal	3	3	-	61
Elk	25	25	-	61
Frontal	19	19	-	61
Isaak	18	18	-	61
Job	4	4	-	61
Olympus	11	11	-	61
Race	8	8	-	61
Southesk Diversion	21	21	-	61
Strike	27	27	-	61
Thistle	25	25	-	61
Thunder	19	19	-	61
Horseguard	1	1	-	61
Brazeau Forks	88	88	-	61
Carvel	135	135	-	61
Chambers Creek	47	47	-	61
Drayton Valley	162	162	-	61
Gap	91	91	-	61
Hairy Hill	182	182	-	61
Phoenix	80	80	-	61
Ramparts	122	122	-	61
Rocky Mountain	49	49	-	61
Shunda	48	48	-	61
Whirlpool	10	10	-	61
Magnolia	7	7	-	61
Vermillion	12	12	-	61
Carcajou	1329	1329	-	61
Dunvegan	256	256	256	61
Mile 232	898	898	-	61
Mile 251	1011	1011	-	61
Vermillion Chutes	75	75	-	61
18th Baseline	210	210	-	61
19th Baseline	337	337	-	61
Bolton	124	124	-	61
Cutbank	174	174	-	61
Kakwa	346	346	-	61
Meander	292	292	-	61
Peace River	253	253	-	61
Sulphur	84	84	-	61

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
ALBERTA (continued)				
Wapiti	228	228	-	61
Watino	346	346	-	61
West Watino	318	318	-	61
Dickson	7	7	-	61
Raven Dam Site	7	7	-	61
Alternative 4	1667	1667	1667	61
Bassano	1	1	-	61
Cochrane	19	19	-	61
Dalemead	112	112	-	61
Eyremore	17	17	-	61
Glenbow	29	29	-	61
Lac des Arcs	15	15	-	61
Radnor	21	21	-	61
Russell	41	41	-	61
Shepard	78	78	-	61
Castle Site (1978)	7	7	-	61
Brocket	14	14	-	61
Fort MacLeod	7	7	-	61
Three Rivers	25	25	-	61
Meridan	45	45	-	61
Rapid Narrows	14	14	-	61
Sub total	**9 762**	**9 762**	**1 923**	
OTHER POTENTIAL	9 051	-	-	61
TOTAL ALL SITES	**18 813**	**9 762**	**1 923**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
BRITISH COLUMBIA				
Peace Site C	900	900	900	60
Keenleyside	240	240	240	55
Murphy Creek	275	275	275	60
Stikine-Iskut	2 900	2 900	2 900	61
Liard River	4 318	4 318	3 190	66
Falls River (Redev)	15	15	15	36
Seven Mile Unit 4	202	202	202	16
Homathko	895	895	710	55
Elaho	340	340	340	70
Border	250	250	250	74
McGregor Lower Canyon	360	360	360	62
Kemano Completion	520	520	520	60
Waneta (Ext)	380	380	380	28
Brilliant (Ext)	150	150	150	44
Shuswap	55	55	55	89
Beatrice Lake	31	31	31	68
Goat River	12	12	12	26
Peace Site E	600	600	-	53
Skeena	1 300	1 300	-	53
Yukon-Taku	3 700	3 700	-	67
Thorsen Creek	3	3	-	53
Duncan	25	25	25	48
OTHER SITES	14 969	-	-	61
Sub total	**32 440**	**17 471**	**10 555**	
TIDAL				
Observation Inlet	660	660	-	35
Sechelt Inlet	54	54	-	35
TOTAL ALL SITES	**33 154**	**18 185**	**10 555**	

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
YUKON				
Mid Yukon	480	480	-	66
Hootalinqua	259	259	-	75
Wolverine	476	476	-	75
Detour Canyon	100	100	-	60
High Granite (III)	414	254	-	75
Braden Canyon	150	150	-	60
Big Salmon	301	301	-	75
Bell/Porcupine River	110	110	-	60
Frances, Upper Canyon	58	-	-	60
Frances, False Canyon	170	58	58	60
Frances, Lower Canyon	80	75	75	60
Liard Basin	244	244	-	60
Liard Canyon	90	90	90	60
Aberdeen Falls	300	300	-	60
Bonnet Plumi	198	198	-	65
Porcupine Canyon	190	190	-	65
Porcupine Diversion	1 241	1 241	-	65
Porcupine/Stewart	83	83	-	60
Slate Rapids	42	42	42	60
Fraser Falls	300	300	-	60
Independence	450	450	-	60
Hoole Canyon	40	40	40	60
Hoole River	15	15	15	60
Ross Canyon	30	30	30	60
Primrose	30	30	-	60
Five Finger Rapids	455	150	-	75
Yukon-Taku	3 692	1 500	-	85
Yukon-Yaiya	4 050	2 000	-	85
Pelly Basin	160	160	-	60
Stewart Basin	150	150	-	60
Upper Canyon/White	16	16	-	60
Lower Canyon/White	16	16	-	60
Kluane Canyon	17	17	-	60
Britannia	459	459	-	75
Tatshenshine (I&II)	160	160	-	60
Donjek	43	43	-	60
Bates Canyon	110	110	-	60
Peel Diversion	755	755	-	65
Ogilvie	896	896	-	75
Dawson	571	571	-	75
Boundary	1 006	1 006	-	75
NWPI	55	55	-	60
Yukon River Basin	121	121	-	60

Remaining Hydroelectric Potential in Canada* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
YUKON (continued)				
Sub total	**18 583**	**13 701**	**350**	
OTHER SITES	-	-	-	
TOTAL ALL SITES	**18 583**	**13 701**	**350**	
N.W.T.				
Anderson	160	160	-	60
Back	2073	2073	1162	60
Burnside	525	525	-	60
Camsell	29	29	-	60
Coppermine	279	279	149	60
Dubawnt River	178	178	-	60
Ferguson	16	16	-	60
Great Bear 1	438	438	204	60
Great Bear 2	414	414	-	60
Hornaday	91	91	-	60
Horton	115	115	-	60
Hayes	120	120	-	60
Hood	52	52	-	60
Kakisa	21	21	13	60
Kazan	64	64	-	60
Maguse	39	39	-	60
Nahanni/Virginia	232	232	216	60
Nahanni	339	339	-	60
Flat	18	18	-	60
Lockhart	387	387	126	60
Pikes Portage	148	148	126	60
Quoich	207	207	-	60
Tha-Anne	41	41	-	60
Taltson	113	113	34	60
Tazin	15	15	-	60
Thelon	188	188	34	60
Thlewiaza	73	73	-	60
Trout	10	10	6	60
Slave	1130	1130	370	60
Sylvia Grinnell	86	86	6	60
Snowdrift	6	6	-	60
Arctic Red	80	80	-	60
Peel	200	200	-	60

REMAINING HYDROELECTRIC POTENTIAL IN CANADA* (continued)

Sites	Gross Potential[1] (MW)	Identified Potential[2] (MW)	Planning Potential[3] (MW)	Capacity** Factor (%)
N.W.T. (continued)				
Rat	450	450	-	60
Keele	75	75	-	60
Mountain	70	70	-	60
Root	55	55	-	60
Redstone	135	135	-	60
Dahadinni	160	160	-	60
Willow Lake	20	20	-	60
La Martre	27	27	27	60
Armshow	20	20	-	60
Anna Maria Port	7	7	-	60
Ward Inlet	15	15	-	60
Petitot	27	27	-	60
Hanbury	246	246	-	60
Prince	4	4	-	60
Maguse	3	3	-	60
Sub total	**9 201**	**9 201**	**2 473**	
OTHER SITES	28	-	-	60
TOTAL ALL SITES	**9 229**	**9 201**	**2 473**	
CANADA TOTAL	**188 191**	**121 467**	**46 084**	

* *Estimated.*

1 *Gross Potential - The total gross resource that could be developed if there were no technical, economic or environmental constraints (excludes sites already developed or under construction).*

2 *Identified Potential - Gross potential less sites that may not be developed for technical reasons.*

3 *Planning Potential - Identified potential less sites that may not be developed for environmental or economic reasons. The planning potential thus comprises all those sites that are considered to be likely candidates for future development.*

** *Capacity factors have been rounded off. In some cases, capacity factors have been estimated using 61 per cent for hydro and 25 per cent for tidal.*

Ext *Extension.*

Redev *Redevelopment.*

Source: Canadian electric utilities and Energy, Mines and Resources Canada.

DEFINITIONS AND ABBREVIATIONS

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (BTu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 50 megawatts of capacity (i.e. of power).

2. Equipment Capacity: The maximum power capability of a piece of equipment. For example, a generating unit might have a rated capacity of 50 megawatts.

Capacity Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Cogeneration: A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

DEFINITIONS AND ABBREVIATIONS

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand Charge: The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kW.h).

Electrical Power: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kW.h). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

DEFINITIONS AND ABBREVIATIONS

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatt hour (GW.h): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

Gross National Product (GNP): The total value of production of goods and services measured at market prices.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Installed Capacity: The capacity measured at the output terminals of all the generating units in a station, without deducting station service requirements.

Interruptible Energy or Power: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

DEFINITIONS AND ABBREVIATIONS

Load: The amount of electric power or energy consumed by a particular customer or group of customers.

Load Factor: The ratio of the average load during a designated period to the peak or maximum load in that same period. (Usually expressed in per cent.)

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MW.h): A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc.

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

DEFINITIONS AND ABBREVIATIONS

Terawatt Hours (TW.h): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.